

Exhibit C

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Decision 12-12-033 December 20, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address
Utility Cost and Revenue Issues
Associated with Greenhouse Gas
Emissions.

Rulemaking 11-03-012
(Filed March 24, 2011)

**DECISION ADOPTING CAP-AND-TRADE GREENHOUSE GAS ALLOWANCE
REVENUE ALLOCATION METHODOLOGY FOR THE INVESTOR-OWNED
ELECTRIC UTILITIES**

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APPENDIX A – Sample Methodologies for Calculating Allowance Value to
Compensate EITE Customers for their Purchased Electricity
Costs Resulting from the Cap-and-Trade Program

APPENDIX B – Proposed Methodology for Calculating Allowance Value to
Compensate Small Businesses for Purchased Electricity Costs
Resulting from the Cap-and-Trade Program

**DECISION ADOPTING CAP-AND-TRADE GREENHOUSE GAS
ALLOWANCE REVENUE ALLOCATION METHODOLOGY
FOR THE INVESTOR-OWNED ELECTRIC UTILITIES**

1. Summary

In accordance with California Public Utilities Code § 748.5,¹ Assembly Bill 32,² and other applicable statutes and regulations, this decision adopts a methodology for allocating greenhouse gas allowance revenues received by California's investor-owned utilities, including small and multi-jurisdictional utilities, as part of California's Cap-and-Trade program. The three large investor-owned utilities, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) are directed to allocate greenhouse gas allowance revenues, including accrued interest, in the following manner:

1. Compensate emissions-intensive and trade-exposed entities (as defined in this decision) using methodologies based upon those developed by the California Air Resources Board to address direct emissions cost exposure under the Cap-and-Trade program;
2. Offset the rate impacts of the Cap-and-Trade program in the electricity rates of small businesses, defined as entities with monthly demand not in excess of 20 kilowatts in more than three months within a twelve-month period, through a volumetrically calculated rate adjustment;
3. Given the disproportionate cost burden currently reflected in upper-tier residential rates and the limited ability to pass Cap-and-Trade costs through to residential customers on the basis of cost responsibility, neutralize the rate impacts

¹ Statutes of 2012, Chapter 39.

² Statutes of 2006, Chapter 488.

of the Cap-and-Trade program on residential electricity rates through a volumetrically calculated rate adjustment.

4. Distribute all revenues remaining after accounting for the revenues allocated pursuant to the prior three uses to residential customers on an equal per residential account basis delivered as a semi-annual, on-bill credit.

PacifiCorp and California Pacific Electric Company are directed to return revenues according to the process set forth above with one exception. Because PacifiCorp and California Pacific Electric Company are statutorily able to allow all residential rates (including lower-tier rates) to rise to reflect the price of carbon, no one class of residential ratepayers will bear disproportionate greenhouse gas costs in relation to any other class. Therefore, PacifiCorp and California Pacific Electric Company shall return all remaining greenhouse gas allowance revenues, after compensating emissions-intensive and trade-exposed entities and small businesses, directly to their residential ratepayers on a per residential account basis delivered semi-annually via an on-bill credit (thus skipping Step 3, above). Bear Valley Electric Service, a Division of Golden State Water Company, as a small utility receiving minimal greenhouse gas allowance revenue, is ordered to return 100% of its greenhouse gas allowance revenue in direct proportion to costs borne by its customers (a volumetric return) through its existing, annual Purchase Power Adjustment Clause proceeding.

Investor-owned utilities are directed to allocate greenhouse gas allowance revenues to all customers in the applicable customer groups set forth in this decision inclusive of Direct Access and Community Choice Aggregator customers in a competitively neutral manner as required by the Cap-and-Trade regulation. Community Choice Aggregator and Direct Access customers shall receive their proportional share of greenhouse gas revenues, and such revenues shall be dispersed according to the methodology set forth above. The total

amount of greenhouse gas revenues that will be available for return to utility ratepayers is wholly dependent upon the market clearing price of greenhouse gas allowances and the number of allowances sold at market. Using the California Air Resources Board floor price and the price at which allowances would become available from the Allowance Price Containment Reserve, the total revenue value ranges from \$5.7 billion to \$22.6 billion between 2013 and 2020 for PG&E, SCE, and SDG&E combined.

In today's decision, we are guided principally by a desire to maintain the carbon price in rates and therefore ensure that the price of goods and services reflects the full cost of carbon in order to send the clearest signal to ratepayers to make the most efficient economic decisions. We believe this outcome most fully comports with the intentions of Assembly Bill 32. However, we acknowledge that, for certain industries and customer groups, the presence of a full carbon price signal in electricity rates immediately upon the commencement of the Cap-and-Trade program may have a deleterious effect that justifies specific treatment. Therefore, as described in this decision, we adopt certain measures to ease the transition toward electricity rates that fully reflect a carbon price signal for these industries and groups.

The greenhouse gas revenue allocation methodology adopted in this decision requires additional record and development before it can be finalized and implemented. If greenhouse gas-related energy costs were immediately recoverable in rates before the greenhouse gas revenue allocation methodology is implemented, retail customers eligible to receive greenhouse gas revenues would see only the cost increase without any countervailing revenues. Therefore, we defer including in rates greenhouse gas costs and revenues for all retail customers until necessary implementation details are resolved.

We decline at this time to allocate any portion of greenhouse gas allowance revenues toward clean energy or energy efficiency measures, preferring to focus our initial efforts on maximizing the amount of revenues returned directly to residential ratepayers (after returning revenues to emissions-intensive and trade-exposed and small business ratepayers). We take this approach to mitigate the increased cost of goods and services that will be ultimately borne by residential ratepayers as businesses pass on the carbon cost embedded in their electricity rates. We do, however, set forth high-level guidelines to be considered if the Commission decides at a later date to direct some portion of greenhouse gas allowance revenue toward clean energy or energy efficiency measures. In that event, we believe that the appropriate venue to consider clean energy or energy efficiency programs or projects that could be funded by greenhouse gas allowance revenue is within those respective proceedings.

This decision also adopts a competitively neutral interim customer education and outreach plan for 2013 administered by the investor-owned utilities on behalf of all customers, including customers of Electric Service Providers and Community Choice Aggregators, and the decision adopts a process to develop a more comprehensive and robust customer outreach and education plan for 2014 and beyond.

This proceeding remains open to address implementation issues related to this decision as well as issues in additional phases and tracks of this rulemaking.

2. Procedural History

The Commission opened this proceeding on March 24, 2011. As provided in the Order Instituting Rulemaking (OIR), numerous parties filed opening prehearing conference (PHC) statements and replies on April 21, 2011 and May 5, 2011, respectively, creating a broad record to inform our initial discussion

of schedule and scope at the June 2, 2011 PHC. On May 11, 2011, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (together, the Joint Utilities) filed a Joint Motion requesting that the Commission issue an interim decision to address the use of allowance revenues to compensate ratepayers for greenhouse gas (GHG) costs that, at the time of filing, were anticipated to be reflected in rates beginning in 2012. The Joint Motion also included a specific interim GHG revenue allocation proposal for 2012. In comments, parties broadly supported the need for an interim decision on the use of GHG allowance revenues for 2012, but several parties objected to the specific interim GHG revenue allocation proposal presented by the Joint Utilities.

During the first PHC, held on June 2, 2011, assigned Administrative Law Judge (ALJ) Jessica T. Hecht suggested dividing Track 1 of this proceeding into two parts, with the first focused on developing an interim mechanism to distribute or otherwise utilize GHG auction revenues in 2012. Adoption of this interim methodology would be followed by a more thorough evaluation of the use of allowance revenues for 2013 and beyond.

On June 20, 2011, the Joint Utilities filed a Joint Exhibit containing more detailed information about the proposal contained in their Joint Motion. In a June 24, 2011 electronic mail ALJ ruling, parties were told to submit by July 13, 2011 their own proposals for the use of revenues received in 2012 as alternatives to the proposal contained in the Joint Motion. This ruling also allowed parties to submit comments on the policy and legal implications of other possible allocations.

On June 29, 2011, California Air Resources Board (ARB) Chairwoman Mary Nichols announced a one-year delay in the enforcement of the Cap-and-

Trade program, until 2013. Because of this delay, the costs of the Cap-and-Trade program would not be reflected in rates until 2013. On July 8, 2011, co-assigned ALJ Semcer sent an electronic mail (e-mail) ruling to parties stating that, based on the delay in enforcement of the Cap-and Trade regulation, an interim decision adopting a revenue allocation mechanism for 2012 by January 1, 2012 was no longer needed. That e-mail ruling also suspended the deadline for submission of alternate proposals and comments. Finally, the ruling set a second PHC for August 1, 2011 and announced a workshop immediately following the PHC to discuss policy objectives for GHG allowance revenue and Low Carbon Fuel Standard (LCFS) credit revenue use.³ On July 22 2011, ALJ Semcer issued a ruling officially denying the Joint Motion for an interim decision, confirming the previous electronic mail rulings suspending the comment schedule, and setting a tentative scope and schedule for the proceeding.

The second PHC was held on August 1, 2011. The *Assigned Commissioner and Administrative Law Judges' Joint Scoping Memo and Ruling*, issued on September 1, 2011, set forth the schedule and scope of this proceeding, and divided the proceeding into three tracks: Track 1, focusing on the allocation of GHG allowance revenue; Track 2 addressing the allocation of LCFS credit revenue; and Track 3, addressing GHG procurement and revenue allocation for gas utilities.

The Scoping Memo ordered parties to submit proposals in Track 1 setting forth possible GHG allowance revenue distribution methodologies. Parties were also directed to respond to the policy objectives discussed at the August 1, 2011

³ The use of LCFS revenues is the subject of Track 2 of this rulemaking and will be addressed in a subsequent decision.

workshop and offer any additional policy objectives for consideration. In addition, the three large investor-owned utilities and PacifiCorp were required to file and serve a Rate Impact Model for use by parties and the Commission in quantifying the rate impacts of different proposals by customer class and/or customer type.

On September 27, 2011, the Joint Utilities filed a proposed rate impact model, and PacifiCorp filed a separate rate impact model for use with its unique rate structure. On October 5, 2011, parties filed 13 proposals⁴ describing a variety of options for the use of GHG revenues. These proposals ranged from a direct volumetric return to all ratepayers to the allocation of funds towards specific programs and technologies. A workshop was held on November 1 and 2, 2011, to discuss the utility Rate Impact Models and the opening proposals. Pursuant to the November 16, 011 *Joint Administrative Law Judge's Ruling Adopting Modified Schedule*, the Joint Utilities and PacifiCorp filed revised rate impact models on December 2, 2011.

⁴ These 13 proposals were filed by the following parties individually or jointly: California Cogeneration Council (CCC), jointly by the California Farm Bureau Federation, the Agricultural Council of California, the California League of Food Processors, and the Agricultural Energy Consumers Association (collectively, the Agricultural Parties), the Direct Access Customer Coalition (DACC), the Division of Ratepayer Advocates (DRA), the Green Power Institute, (GPI), jointly the California Large Energy Consumers Association (CLECA), the California Manufacturers and Technology Association, and the Energy Producers and Users Coalition (EPUC) (collectively, the Large Users), Marin Energy Authority (MEA), jointly the Natural Resources Defense Council, Sierra Club California, the Greenlining Institute, Union of Concerned Scientists, Local Government Sustainable Energy Coalition, National Consumer Law Center, Climate Protection Campaign, California Housing Partnership Corporation, and the Community Environmental Council (collectively, the Joint Parties), Noble Americas Energy Solutions, LLC (Noble Americas), the Joint Utilities, PacifiCorp, the Solar Energy Industries Association (SEIA)(formerly the Solar Alliance), and The Utility Reform Network (TURN).

On January 6, 2012, parties submitted 12 final proposals.⁵ Some of the proposals represented refinements of opening proposals,⁶ and others were new proposals from parties that did not submit opening proposals.⁷ In addition to these 12 revised proposals, CCC, Noble Americas, and TURN did not submit revised proposals but relied upon their opening proposals for consideration. Finally, in response to an oral ruling of the ALJs at a May 23, 2012 workshop, Bear Valley Electric Service, a division of Golden State Water Company (Bear Valley) and California Pacific Electric Company (CalPeco) submitted proposals for the use of their respective portion of GHG allowance revenues. As a result, the Commission considers 18 formal proposals in this decision.⁸ A second workshop was held on January 11, 2012 to further discuss revised and new proposals. On January 31, 2012, numerous parties⁹ filed opening comments on

⁵ Final proposals do not reflect updates submitted by parties after passage of Senate Bill (SB) 1018.

⁶ The Agricultural Parties, DACC, DRA, GPI, the Large Users, MEA, the Joint Parties, the Joint Utilities, PacifiCorp and SEIA filed revised proposals.

⁷ City and County of San Francisco (CCSF) and Tesoro Refining and Marketing Company (Tesoro) filed new proposals on January 3, 2012.

⁸ Where parties submitted revised proposals, the Commission has only considered those revisions and has not considered the opening proposals, unless the proposals were sequential, such as that of the Large Users. Noble Americas' proposal more closely reflects comments than a specific proposal, but is included amongst the proposals nevertheless. Bay Area Rapid Transit (BART) did not submit a formal proposal; however, BART's opening comments most closely reflect a proposal and are therefore being evaluated as an 18th proposal.

⁹ The Agricultural Parties, BART, CCC, the California Construction Industry Labor Management Trust, the California Energy Efficiency Industry Council (Efficiency Council), CLECA, CCSF, DACC, DRA, EPUC, GPI, the Independent Energy Producers Association (IEP), the Large Users, MEA, the Joint Parties, the Joint Utilities, PacifiCorp, Tesoro, TURN, USS-POSCO Industries, Western Power Trading Forum (WPTF) filed opening comments.

the GHG revenue allocation proposals, and reply comments were filed on February 14, 2011.¹⁰ In addition, February 14, 2011 was the deadline for parties to file requests for hearings on Cap-and-Trade revenue allocation; no requests were received.

On May 23, 2012, the ALJs convened a workshop to explore in further detail proposals submitted by parties and to discuss questions related to implementation of the various GHG revenue allocation methodology proposals. In order to further develop the record, on June 1, 2012, PG&E, SCE, SDG&E and PacifiCorp submitted additional responses addressing such items as the administrative cost of implementing various proposals and the impact of various proposals on master-meter customers, among other issues.

On July 11, 2012, in response to the passage of SB 1018,¹¹ which sets forth specific parameters on the use of GHG allowance revenues, the ALJs released a ruling soliciting comment by parties on the various provisions contained in Public Utilities Code § 748.5.¹² Multiple parties filed opening¹³ and reply comments¹⁴ on August 1, 2012 and August 13, 2012, respectively. In addition, on August 12, 2012 the assigned Commissioner and ALJs released an amended

¹⁰ The Agricultural Parties, Bear Valley, CCC, CLECA, DACC, DRA, EPUC, GPI, MEA, the Joint Parties, the Joint Utilities, SEIA, Tesoro, TURN, the University of California, USS-POSCO Industries, and WPTF filed reply comments.

¹¹ Statutes of 2012, Chapter 39.

¹² SB 1018 adopts Public Utilities Code Section 748.5. Statutory citations are to the California Public Utilities Code, unless otherwise stated.

¹³ The Agricultural Parties, CCC, CCSF, CLECA, DACC, DRA, the Efficiency Council, GPI, IEP, the Joint Parties, the Joint Utilities, MEA, PacifiCorp, SEIA, Tesoro, and USS POSCO Industries filed opening comments on SB 1018.

¹⁴ The Agricultural Parties, DACC, GPI, the Joint Parties, SEIA and Tesoro filed reply comments on SB 1018.

scoping memo expanding the scope of this proceeding to address the provisions of § 748.5, as well as issues relating to GHG cost responsibility in contracts pre-dating passage of Assembly Bill (AB) 32.¹⁵ This latter issue will be addressed in a separate phase of the proceeding.

3. Background

California is a national pacesetter in pursuing policies that promote the reduction of GHG emissions, especially emissions related to the production and delivery of energy services. The California Public Utilities Commission (Commission) opened this rulemaking to address, among other issues, the use of revenues that electric utilities will generate from the auction of allowances allocated to them by the ARB under its Cap-and-Trade program. In this decision, we adopt a methodology for allocating GHG allowance revenues received by California's investor-owned utilities, including small and multi-jurisdictional utilities. The utilities covered by today's decision are PG&E, SCE, SDG&E, PacifiCorp, CalPeco,¹⁶ and Bear Valley.¹⁷

3.1. Overview of Cap-and-Trade in California

The Global Warming Solutions Act of 2006, AB 32, caps California's GHG emissions at 1990 levels, with this level to be reached by 2020. As the agency responsible for implementing AB 32, ARB designed a statewide GHG Cap-and-Trade program that works in tandem with existing policies and has the flexibility to link with other jurisdictions, notably the Western Climate Initiative, a

¹⁵ Statutes of 2006, Chapter 488.

¹⁶ Formerly Sierra Pacific Power Company, CalPeco purchased Sierra Pacific Power Company in a transaction approved by this Commission in Decision (D.) 10-10-017.

¹⁷ In 2011, Mountain Utilities, which is listed as a covered entity in the Cap-and-Trade regulation, became the Kirkwood Meadows Public Utilities District, a publicly owned utility, and is no longer within this Commission's jurisdiction (see D.11-06-032).

consortium of U.S. and Canadian states. ARB adopted the final Cap-and-Trade regulation in December 2011, and the regulation became effective on January 1, 2012. California's Cap-and-Trade program creates an economy-wide cap on major sources of GHG emissions, including refineries, power plants, industrial facilities and transportation fuels.

At a most basic level, ARB has three main responsibilities under the Cap-and-Trade program: (1) cap GHG emissions by issuing a limited number of tradable permits (allowances) equal to the emissions cap; (2) reduce the cap over time to reach 1990 level emissions by 2020; and (3) enforce the cap by requiring each entity that operates under the cap to turn in one allowance for every metric ton of carbon dioxide equivalent gas (MTCO₂e) that it emits. During the first compliance period, consisting of 2013 and 2014, the cap will apply to approximately 37% of California's economy-wide emissions. Starting with the second and third compliance periods, from 2015 to 2017 and 2018 to 2020, respectively, the cap will include approximately 85% of emissions.¹⁸ Because allowances are tradable, the cap effectively creates a market for GHG allowances, which encourages entities to make efficient decisions about how to reduce emissions. ARB has taken an allowance allocation approach that combines auction-based allocation with a limited free (direct) allocation to individual entities for the purpose of protecting electricity customers and advancing other AB 32 objectives, providing transition assistance to certain industries, and limiting emissions leakage.

¹⁸ ARB, California's Cap-and-Trade Program Initial Statement of Reasons (ISOR), October 2011 at II-9.

During the first compliance period of the Cap-and-Trade program, which begins in 2013, the cap will cover electricity generation, including imports from outside California, as well as large industrial sources and processes with annual GHG emissions at or above 25,000 MTCO_{2e}, and carbon dioxide (CO₂) suppliers. The program will expand in 2015, the beginning of the second compliance period, to include emissions from fuels used for transportation, as well as emissions from fuel combusted by all commercial, residential and small industrial sources that have emissions below 25,000 MTCO_{2e}. Under the current regulations, all sectors will be covered through 2020. Regulated gases include CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride.

3.1.1. Electricity Sector Compliance Obligation

The Cap-and-Trade program regulates emissions from both imported electricity and electricity generated within California. The first party that places power onto the California grid is responsible for emissions associated with that power under the regulation, which treats all parties equally. For in-state generation, the covered entity is the source of generation. In-state generators are only covered if their emissions exceed 25,000 MTCO_{2e}, with their compliance obligation equal to the facility's total emissions.

For imported electricity, the covered entity is the first entity to deliver electricity onto the California grid. Electricity deliverers can include electrical distribution utilities ("retail providers" that sell electricity to retail customers) and marketers (those that buy and sell in the wholesale electricity market). If the emissions from the generating facility are known, this is referred to as specified power, and the associated compliance obligation is equal to the known emissions. If the facility's emissions are unknown – for electricity generated

outside California and imported into the State from an unknown source – then the source is referred to as unspecified power. For unspecified power, compliance obligations are determined by multiplying an emissions factor by the megawatt-hours (MWh) delivered. The emission factor is an administratively determined value based on the average emissions associated with the available electricity generation that could be sold on the spot market and brought into California.

3.1.2. Allowances and Allocation

Allowances are the currency of the Cap-and-Trade program. Each allowance is a tradable permit representing one metric ton of carbon dioxide equivalent gas. The value of GHG allowances derives from the economy-wide, annually decreasing cap on GHG emissions, along with the requirement that each entity covered by the Cap-and-Trade regime surrender compliance instruments – GHG allowances and a limited number of GHG offsets – equal to the entity’s annual GHG emissions. The total number of allowances ARB issues in any given year is equal to the state-wide GHG cap for that year, and allowances each have a “vintage,” the first year in which the emissions they represent and can be retired against occur. Individual covered entities do not have specific emission limits; rather, they must account for their emissions by acquiring and surrendering allowances equal to their emissions within a given compliance period.¹⁹

¹⁹ The Cap-and-Trade program is divided into three compliance periods; 2013-2014, 2015-2017, and 2018-2020. In the year following any given year within a compliance period, regulated entities are required to retire allowances or offsets sufficient to cover at least 30% of their emissions in that year. Following the end of a given compliance period, entities are required to retire allowances sufficient to cover the balance of any uncovered emissions accrued over the entire compliance period.

Allowances encourage entities to make efficient decisions about how to reduce emissions. Those with limited ability to cost-effectively reduce emissions will buy allowances, and those that are able to reduce their emissions may need to buy fewer allowances or have a surplus of allowances that they can sell on secondary markets. The market price of allowances creates a price signal for GHG emissions and provides incentives for the market to find efficient ways to reduce emissions. In this way, the market price of allowances closely reflects the marginal cost of GHG abatement.

ARB uses two methods of distributing allowances: direct (free) allocation and auction. In its Final Regulation,²⁰ ARB granted to electric distribution utilities, including the investor-owned utilities and the publicly-owned utilities, a direct allocation of allowances for the purpose of protecting electricity customers and advancing AB 32 objectives. Under this allocation methodology, the investor-owned utilities received an allowance allocation on behalf of all customers of the distribution utility, which includes direct access (DA) and community choice aggregation (CCA) customers. The investor-owned utilities subject to our jurisdiction must consign all of their allowances to auction with the proceeds to be used for the benefit of all ratepayers, including DA and CCA ratepayers.

The allowance allocation to individual utilities in any given year is equal to the total 97.7 MMTCO₂e allocated to electrical distribution utilities in 2012 (inclusive of investor-owned and publicly-owned utilities) multiplied by a cap adjustment factor, which decreases annually through the 2013-2020 period, and a

²⁰ California Code of Regulations, Title 17, Division 3, Subchapter 10 (Climate Change), Article 5, §§ 95800-96023 (17 CCR §§ 95800-96023).

percentage allocation factor based on the utility's proportion of the projected emissions in the electricity sector. The amount of allowances allocated to each investor-owned utility is contained in Table 1 below. The schedule of allowance allocations to the electricity sector as a whole was calculated by ARB using 2008 historical emissions for the sector, including emissions associated with purchases from combined heat and power facilities, multiplied by 90%. The per year allocation, beginning in 2012, was then calculated by linearly declining this amount such that it is reduced to 85% of its initial 2012 level by 2020.

To determine the allocation of allowances to each of the electric distribution utilities within the electricity sector, ARB calculated each utilities' anticipated share of the overall cost burden under the Cap-and-Trade program, adjusted to recognize cumulative energy efficiency and early investment in renewable energy resources.

Table 1: Annual Allowance Allocation per Utility (MTCO₂e)²¹

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|-------------|------------|------------|------------|------------|------------|------------|------------|------------|
| PG&E | 24,947,243 | 24,786,927 | 23,993,415 | 23,691,151 | 24,113,145 | 23,347,893 | 23,102,416 | 22,639,599 |
| SCE | 32,603,468 | 31,594,859 | 31,399,111 | 29,550,280 | 26,868,833 | 25,889,682 | 25,017,535 | 24,704,540 |
| SDG&E | 6,919,340 | 6,549,142 | 6,426,429 | 6,406,805 | 6,460,042 | 6,288,321 | 6,186,936 | 6,143,946 |
| PacifiCorp | 723,725 | 728,106 | 730,526 | 737,440 | 745,624 | 752,553 | 759,349 | 767,731 |
| Bear Valley | 58 | 56 | 55 | 63 | 62 | 61 | 59 | 58 |
| CalPeco | 216,846 | 220,658 | 224,485 | 225,543 | 229,404 | 227,253 | 227,867 | 226,639 |

²¹ Derived from Table 9-3: Percentage of Electric Sector Allocation Allocated to Each Utility, 17 CCR § 95892(e).

3.1.2.1. Allocation for Industry Assistance

In addition to the direct allocation of allowances to the electricity sector, ARB also freely allocated allowances to certain industrial facilities to address the risk of emissions leakage.²² Leakage risk is the risk that some California manufacturers will face an immediate decline in profitability as a result of the GHG allowance allocation approach adopted in the Cap-and-Trade program, and this decline in profitability will inhibit these entities from investing in cost-effective emissions reductions. Introducing an environmental regulation in one jurisdiction can cause production costs and prices in that jurisdiction to increase relative to costs in jurisdictions that do not introduce comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction toward goods produced elsewhere. As a result, the reduction in production and emissions in the implementing jurisdiction is offset by increased production and emissions elsewhere. This offsetting increase in emissions is called emissions leakage. To prevent leakage and provide transition assistance, an industrial facility's GHG costs that cannot be recovered through the price of its goods can be reduced through a free allowance allocation.

ARB determines risk of emission leakage by evaluating whether an industry is emissions-intensive and trade-exposed (EITE). Facilities understood to be EITE in common usage²³ are more formally referred to in the Cap-and-Trade regulation as Industrial Covered Entities that qualify for Industry Assistance.²⁴ Emissions intensity is an indicator of the impact that carbon pricing

²² ISOR at II-26.

²³ There is no official definition for EITE in the Cap-and-Trade regulation.

²⁴ See 17 CCR § 95870 et seq. and industries listed by North American Industry Classification System (NAICS) Code in *Table 8-1: Industry Assistance*

will have on an industrial sector's economic output. Those with higher emissions per unit of output are considered to be more emissions intensive. Trade exposure is a measure of the degree of competition a sector faces from entities operating outside of the Cap-and-Trade program and the associated ability of consumers to shift demand to those providers that do not bear any carbon costs. Without assistance, the competitiveness of industries that are both highly emissions-intensive and trade-exposed has the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements. In the Cap-and-Trade regulation, ARB set forth several methodologies for allocating allowances to Industrial Covered Entities that qualify for Industry Assistance. The allocation distributes allowances based on various factors, with the specific factors varying based on industrial classification and an assessment of leakage risk (low, medium, or high). The amount of freely allocated allowances steps down at different rates (dependent upon leakage risk) between 2013 and 2020.

Pertinent to today's decision is that, in developing its approach to allocating allowances to Industrial Covered Entities that qualify for Industry Assistance, ARB did not address the indirect emissions costs industrial entities will face through their purchases of electricity, which, given the approach we take in this decision, will generally reflect carbon prices as a result of Cap-and-Trade program implementation. Because such industries are trade-exposed, the imposition of carbon pricing embedded in the price of electricity creates leakage risk similar to the leakage risk resulting from direct compliance costs. Furthermore, there may be sectors or industries that, although not designated as requiring Industry Assistance by ARB, may face leakage risk as a result of the embedded price of carbon in electricity rates. For example, a sector may not

qualify for Industry Assistance because their emissions intensity is driven largely by their indirect emissions, or a facility may fall within a sector that qualifies for Industry Assistance but the facility has emissions less than 25,000 MTCO_{2e} (and is therefore is not required to surrender allowances for their direct emissions under the cap). Such sectors and facilities may be unable to pass through the increased costs of electricity to end users for many reasons, including being trade-exposed.

3.1.3. Allowance Auctions

ARB initially intended that two general auctions would be held in 2012, but, as a result of the delay of the first compliance period to 2013, only one auction was conducted, on November 14, 2012. The investor-owned utilities are required to sell a portion of their existing allowance allocation at the 2012 auction and the remaining amount of their 2013 vintage allowance allocation at the auctions to be held quarterly in 2013. Going forward, within each calendar year after 2012, investor-owned utilities must offer for sale at auction all allowances that were issued from budget years that correspond to the current calendar year as well as unsold allowances remaining from budget years prior to the current calendar year.²⁵

3.1.4. Allowance Value

If one assumes that the lowest possible sale price for an allowance is ARB's auction floor price (approximately \$10 per MTCO_{2e} in 2013, increasing annually by 5% plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers) and the upper bound is the price of the first tier of allowances

²⁵ 17 CCR § 95892(c)(2).

in ARB's Price Containment Reserve²⁶ (\$40.00 per MTCO₂e, escalating annually), then the value of allowances allocated to the investor-owned utilities will be worth between approximately \$650 million (assuming the market clears) and \$2.6 billion in 2013. Using these same parameters, the estimated value of allowances over the course of the Cap-and-Trade program is between \$5.7 and \$22.6 billion for PG&E, SCE and SDG&E, combined.²⁷

3.2. Guiding Legislation and Regulation

There are numerous sources of legislation and regulation that guide our decision today. These statutes and regulations lay the foundation on which we build a methodology for allocating GHG allowance revenues. In this section, we highlight relevant portions of several regulations and statutes in order to provide context for readers of this decision.

3.2.1. California Code of Regulations, Title 17

Sections 95800-96023 of Title 17 of the California Code of Regulations (CCR) codify the rules that govern the Cap-and-Trade program in California. We rely on the broad authority set forth in this regulation to determine a methodology for the allocation of GHG allowances. While we rely upon the regulation in its entirety as it pertains to the electricity sector, we particularly note the following sections:

²⁶ The Allowance Price Containment Reserve (Reserve) is a mechanism adopted by ARB to protect against the possibility of high market prices. The Reserve gives covered entities access to an extra reserve of allowances at set prices as a hedge against higher costs that might otherwise prevail.

²⁷ This is calculated as a simple sum of the number of allowance allocated to each of the three large investor-owned utilities each year, multiplied by the assumed allowance prices for each year.

- A) Sections 95892(d)(2-5), which adopt limitations on the use of GHG auction proceeds and allowance revenue, are provided below:
- 2) Proceeds obtained from the monetization of allowances directly allocated to the investor owned utilities shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional requirements set forth in §§ 95892(d)(3-5) and 95892(e).²⁸
 - 3) Auction proceeds and allowance value obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of the electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.
 - 4) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers²⁹ and community choice aggregators.
 - 5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32, is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.
- B) Table 8-1 of § 95870, which lists industries eligible to receive Industry Assistance³⁰ and ranks their leakage risk as low, medium, or high.

²⁸ 17 CCR § 95892(e) sets forth reporting requirements by the investor-owned utilities to ARB detailing, among other things, the amount of GHG allowance revenue value received and how the use of revenues complied with the codification of AB 32; California Health and Safety Code §§ 38500 et seq.

²⁹ In other words, DA customers.

- C) Section 95891, which sets forth the GHG allowance allocation methodology for those industries eligible to receive Industry Assistance. This section includes, among other items, Table 9-1, which adopts industry benchmarking factors.
- D) Table 9-2 of § 95891, which sets forth the Cap Adjustment Factors for all other entities receiving direct allowance allocations.

3.2.2. Senate Bill 695

SB 695,³¹ adopted in 2009, is a comprehensive piece of legislation that amends and adds sections to the Public Utilities Code pertaining to energy. For the purposes of this decision, the relevant sections are § 739.1,³² which sets forth limitations on increases to rates in the California Alternate Rates for Energy³³ (CARE) program, and § 739.9, which sets the parameters by which all other non-CARE residential rates may be increased.

SB 695 places restrictions on the Commission's ability to increase PG&E, SCE, and SDG&E's lower-tier (Tiers 1 and 2) residential rates (CARE and non-CARE) throughout the duration of the Cap-and-Trade program. Annual increases to PG&E, SCE and SDG&E's non-CARE Tier 1 and 2 rates are pegged to the consumer price index plus 1%, with an upper limit of 5%. Tier 1 rates are further prohibited from exceeding 90% of each utility's system average rate.

³⁰ As described in more detail below, industries that are eligible to receive Industry Assistance are allocated GHG allowances directly according to the formulas adopted in § 95891.

³¹ Statutes of 2009, Chapter 337.

³² Due to the length and complexity of these Public Utilities Code sections, they are not copied in their entirety here.

³³ § 739.1(4)(b)(1) establishes CARE rates to provide assistance to low-income electric and gas customers with annual household incomes that are no greater than 200% of the federal poverty guidelines.

Annual increases to PG&E, SCE and SDG&E's CARE Tier 1 and 2 rates are pegged to increases in CalWORKs benefits, with an upper limit of 3%. Because CalWORKs benefits have not increased since SB 695 was enacted, CARE Tier 1 and 2 rates have remained frozen. SB 695 effectively prohibits Tier 1 and 2 rate increases to cover GHG costs. Barring any volumetric return, upper-tier residential rates (including, to a limited extent, Tier 3 CARE customers), would have to absorb the GHG costs for lower-tier consumption. Thus, residential customers on upper-tier rates would bear a disproportionate share of GHG costs compared to customers on lower-tier rates. Importantly, the above restrictions do not apply to the three small and multi-jurisdictional utilities, PacifiCorp, CalPeco and Bear Valley.

3.2.3. Section 748.5

The Commission opened this rulemaking on March 24, 2011. Since that time, we have solicited proposals from parties setting forth various uses of GHG allowance revenues. The proposals, discussed in more detail below, offered a wide variety of options for consideration including directing revenues towards energy efficiency and clean energy programs and returning revenues directly to all ratepayers in proportion to their costs due to the Cap-and-Trade program.

On June 27, 2012, Governor Brown signed SB 1018, which, among other actions, added § 748.5 to the Public Utilities Code setting forth specific parameters on the use of GHG allowance revenues by the electric utilities regulated by this Commission. Upon enactment of § 748.5, many parties amended their initial proposals to comport with its provisions. Section 748.5 reads as follows:

(a) Except as provided in subdivision (c), the commission shall require revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of

greenhouse gas allowances to electric utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations to be credited directly to the residential, small business, and emissions-intensive trade-exposed retail customers of the electrical corporation.

(b) Not later than January 1, 2013, the commission shall require the adoption and implementation of a customer outreach plan for each electrical corporation, including, but not limited to, such measures as notices in bills and through media outlets, for purposes of obtaining the maximum feasible public awareness of the crediting of greenhouse gas allowance revenues. Costs associated with the implementation of this plan are subject to recovery in rates pursuant to Section 454.

(c) The commission may allocate up to 15 percent of the revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of greenhouse gas allowances to electrical distribution utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations, for clean energy and energy efficiency projects established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source.

Section 748.5 sets a basic framework that must be followed in adopting a GHG allowance revenue distribution methodology; however, it leaves much to this Commission's discretion, and there are several sources of ambiguity. Terms requiring interpretation include "small business" and "emissions-intensive and trade-exposed." Implementation aspects left to the discretion of the Commission include determining the methodology for providing a direct return to eligible retail customers and selecting the percentage of revenues, if any, that will be allocated toward clean energy and energy efficiency projects, not to exceed 15%. We explore all of these discretionary issues in detail in this decision.

3.3. Previous Commission Direction

In addition to the guidance and parameters contained in the various statutes and regulations described above, the Commission itself has set forth its preliminary thinking on the use of GHG allowance revenue. On October 22, 2008, the Commission issued D.08-10-037, the *Final Opinion on Greenhouse Gas Regulatory Strategies*, in Phase 2 of Rulemaking (R.) 06-04-009. That decision provided detailed recommendations to ARB as it implemented AB 32. Section 5.5 of D.08-10-037 includes discussion of the proper uses for GHG emissions allowance auction proceeds received by retail providers of electricity:

We agree with parties that all auction revenues should be used for purposes related to AB 32. ... In our view, the scope of permissible uses should be limited to direct steps aimed at reducing GHG emissions and also bill relief to the extent that the GHG program leads to increased utility costs and wholesale price increases. It is imperative, however, that any mechanism implemented to provide bill relief be designed so as not to dampen the price signal resulting from the Cap-and-Trade program.

Ordering Paragraph 15 in D.08-10-037 is particularly relevant to today's decision:

We recommend that ARB require that all allowance auction revenues be used for purposes related to Assembly Bill (AB) 32, and that ARB require all auction revenues from allowances allocated to the electricity sector be used to finance investments in energy efficiency and renewable energy or for bill relief, especially for low income customers.³⁴

³⁴ D.09-10-037 at 227.

3.4. Impact of Cap-and-Trade on Electricity Rates

As described above, first deliverers of electricity to the grid, including electricity generators, electric distribution utilities, and marketers, are covered entities that have a compliance obligation under Cap-and-Trade. These entities, like all others with a compliance obligation, will procure GHG allowances during ARB's quarterly allowance auctions at a clearing price set by the market and via secondary market transactions. The cost of procuring GHG allowances for each unit of emissions created by the production of electricity will ensure that bids into the California electricity market reflect the marginal abatement cost of GHG emissions. This increased cost of electricity production will ultimately be passed through to the end user of electricity – the retail electricity ratepayer (except where prohibited by law) – resulting in higher retail electricity rates.

PG&E, SCE and SDG&E submitted a joint rate impact model to calculate the impact of Cap-and-Trade costs on rates.³⁵ Using this model and 2013 forecasts regarding the investor-owned utilities' GHG cost exposure,³⁶ we are able to examine the general impacts of the Cap-and Trade program on electricity rates absent any revenue return to neutralize these rate impacts. The table below shows estimated ranges of bill increases for different customer classes, assuming an allowance cost of \$10.00 (the 2013 floor price) and an allowance cost of \$40 (the 2013 first tier Reserve price). The numbers in these tables roughly

³⁵ PacifiCorp also submitted a rate impact model. Both models were designed to calculate not only the impact of Cap-and-Trade costs on rates, but also the compensating effect of using revenues generated from the sale of emissions allowances to provide offsetting bill credits.

³⁶ We examined issues related to GHG costs in R.10-05-006, the rulemaking that addresses long-term planning procurement activities for each of the investor-owned utilities.

correspond to the impacts for a typical commercial or residential customer in the investor-owned utilities' service territories.³⁷

Table 2: Estimated Bill Increases for Various Customer Classes

| | Allowance Price = \$10.00/MTCO ₂ e | Allowance Price = \$40.00/MTCO ₂ e |
|--|--|--|
| Residential = 500 kilowatt-hour (kWh)/Month | 0.7% - 1.0% Increase | 2.6% - 3.8% increase |
| Residential = 1000 kWh/Month | 1.5% - 2.5% Increase | 5.9% - 9.8% increase |
| Residential = 1500 kWh/Month | 1.6% - 2.7% Increase | 6.3% - 10.8% increase |
| | | |
| Commercial = 750 kWh/Month | 1.0% - 1.4% Increase | 4.0% - 5.5% increase |
| Commercial = 1500 kWh/Month | 1.1% - 1.3% Increase | 4.3% - 5.7% increase |
| Commercial = 3000 kWh/Month | 1.1% - 1.5% Increase | 4.5% - 5.8% increase |

As shown in Table 2, the impact of the Cap-and-Trade program on the bills of high-use residential customers is proportionately higher than the impact to lower-use customers (those under 500 kWh). Because of statutory limits set by SB 695 on increases to lower-tier residential rates, higher usage residential customers pay a disproportionate share of the carbon costs relative to lower-usage customers, as a relatively smaller share of their consumption will be affected by the cost of the Cap-and-Trade program.

We can also estimate the impact of the Cap-and-Trade program on system average rates within the broader policy context of the Cap-and-Trade program

³⁷ The numbers in this table are calculated based on a rate structure deemed representative by the investor owned utilities, given specific cost assumptions. These are for illustrative purposes only and do not represent actual rates of any utility. These illustrative rates do not account for any additional energy efficiency or distributed generation a given customer might deploy in response to higher rates.

using a model, called the E3 model, developed in R.06-04-009.³⁸ The E3 model can compare rates with and without Cap-and-Trade-related costs, holding all other variables constant. Using this approach, and the “accelerated” policy scenario defined in that model,³⁹ we can estimate the incremental impact of carbon costs on average aggregate investor-owned utility rates.⁴⁰ The table below shows that the Cap-and-Trade program results in rate increases between 2% and 8%, depending on the price of allowances.

Table 3: Impact of Cap-and-Trade on Aggregate System Average Rates⁴¹

| | No Carbon Price (\$/kWh) | CO2 Price Floor ⁴² | | CO2 Price Ceiling ⁴³ | |
|------|-----------------------------|-------------------------------|----------|---------------------------------|----------|
| | | (\$/kWh) | % Change | (\$/kWh) | % Change |
| 2013 | 0.157 | 0.161 | 2.00% | 0.171 | 8.36% |
| 2014 | 0.161 | 0.165 | 2.02% | 0.175 | 8.40% |
| 2015 | 0.166 | 0.169 | 2.04% | 0.180 | 8.46% |
| 2016 | 0.170 | 0.173 | 2.05% | 0.184 | 8.50% |
| 2017 | 0.174 | 0.177 | 2.07% | 0.188 | 8.54% |

³⁸ In R.06-04-009, the Commission evaluated options for allocating carbon allowances among California utilities.

³⁹ The “accelerated policy scenario” assumes 33% Renewables Portfolio Standard by 2020, ‘high case’ energy efficiency by 2020, and increased GHG savings from combined heat and power (CHP) relative to the ‘reference scenario.’
http://ethree.com/documents/GHG%20update/CPUC_GHG_Revised_Report_v3b_update_Oct2010.pdf

⁴⁰ Uses the 2011 Market Price Referant assumption for annual gas prices.

⁴¹ In 2008 real dollars.

⁴² The price floor is based on the auction reserve price established by ARB. 17 CCR § 95911(a)(b)(5).

⁴³ The price ceiling is based on the schedule of prices establish by ARB for the first tier of allowances in the allowance price containment reserve. 17 CCR § 95913(d)(2).

| | | | | | |
|------|-------|-------|-------|-------|-------|
| 2018 | 0.178 | 0.181 | 2.08% | 0.193 | 8.56% |
| 2019 | 0.181 | 0.185 | 2.09% | 0.197 | 8.58% |
| 2020 | 0.185 | 0.189 | 2.10% | 0.201 | 8.61% |

4. Proposals

Parties initially submitted a wide variety of proposals setting forth various options the Commission could consider in determining how to allocate GHG allowance auction revenue. However, upon passage of SB 1018, several parties provided revised proposals to comport with § 748.5. This section provides a broad overview of the most up-to-date proposals submitted by the various parties.

The proposals submitted by parties generally fell into two main categories: 1) comprehensive proposals detailing suggested uses for all of the revenue generated from GHG allowance auctions, and 2) issue-specific proposals addressing a specific situation, industry group, technology, or customer class.

Comprehensive proposals can be divided into two additional categories:

1) proposals that support direct return of all GHG allowance revenue to customers, although proposals vary on the suggested methodology (we refer to these as “direct return proposals”), and 2) proposals that support the use of some portion of the revenues for investment in energy efficiency or clean energy, in addition to, and often before, the direct return of remaining allowance revenues to customers (we refer to these as “hybrid proposals”). All comprehensive proposals support a direct return of at least some portion of revenues to ratepayers. Direct return proposals range from returning revenues to all retail customers, both residential and commercial/industrial, in proportion to costs incurred (volumetric return), to returning revenues solely to residential customers on an equal dollar amount basis. Proposals also differ on the

mechanism for returning revenues to customers, for example, applying revenues towards a customer's utility bill (on-bill) or returning revenues through a separate check (off-bill).

4.1. Proposed Methodologies for Direct Return of Revenues to Customers

Section 748.5 (a) mandates that, with the exception of revenues directed towards clean energy or energy efficiency, GHG revenues, including accrued interest, shall be credited directly to residential, small business, and emissions-intensive and trade-exposed retail customers of the investor-owned utilities. In response to the July 11, 2012 ALJ Ruling seeking comment on the impacts of the new code section, parties disagreed on whether § 748.5(a) is restrictive (meaning that GHG allowances revenues can be credited only to the listed customer groups) or permissive (meaning that GHG revenues must be returned, at a minimum, to the listed customer groups but may also be returned to others). The various approaches to the allocation of funds to different types of customers, and different methods to return the funds, are described below.

4.1.1. Return GHG Revenues to Customers In Proportion to Costs Incurred (Volumetric, On- or Off-Bill)

The Joint Utilities suggest that all GHG allowance revenues received by the utilities be returned directly to all utility retail customers, including CCA and DA customers, via an on-bill credit in proportion to not only the Cap-and-Trade costs incurred, but rather all AB 32 costs, including costs related to renewable energy and energy efficiency programs. The Joint Utilities propose to return GHG allowance revenues to customers via the reduction of a distribution rate component that all customers, including DA and CCA customers, pay. Under this proposal, all GHG allowance revenues would be allocated to customers in proportion to their Cap-And-Trade program costs included in their generation

rates, calculated on a cents-per-kWh basis. Both costs and revenues would be included in rates based on an Energy Resource Recovery Account (ERRA) forecast approved by the Commission, which would be adjusted through the use of balancing accounts based on the actual costs incurred and allowance revenues returned. In this way, the Joint Utilities propose that customers receive the benefit of the allocated GHG allowance revenues in proportion to and at the same time as they incur AB 32 costs, i.e. monthly.⁴⁴ The Joint Utilities argue that any carbon price signal included in residential retail rates would not be accurate because Tiers 1 and 2 rates are protected from Cap-and-Trade-related cost increases as a result SB 695. Because of this, the Joint Utilities note that customers on Tier 3 and above rates will see a disproportionate carbon price signal. The Joint Utilities' proposal is supported in its entirety by Noble Americas, among others.

DRA initially proposed that 90% of GHG allowance revenue be used to provide bill relief via an off-bill annual rebate for those customers who bear Cap-and-Trade costs with the remaining 10% allocated towards a specific energy efficiency program. However, DRA interprets SB 1018 as limiting the Commission to returning revenue only to certain customer classes. For this reason, after the passage of SB 1018, DRA revised its proposal to recommend that EITE, small business and residential customers that bear Cap-and-Trade costs be compensated for their Cap-And-Trade costs through a volumetric on-bill return

⁴⁴ It is important to note that CCA and DA customers will receive GHG allowance revenue value based upon the emissions profile of the utility from which they receive distribution service (currently PG&E for MEA and CCSF). Therefore, the GHG allowance revenues received by CCA and DA customers will not match their GHG costs, which could be greater or less than those of PG&E's bundled customers (depending upon the emissions profile of the CCA or DA provider's portfolio).

with remaining revenues distributed evenly among all residential ratepayers as an annual dividend check.

In the issue-specific proposals, the Large Users, who are primarily concerned with compensation of EITE customers, support a volumetric return of most GHG allowance revenues to non-EITE ratepayers; however, the Large Users argue that only costs directly attributable to the Cap-and-Trade program, and not all AB 32 costs, should be directly returned to customers. Similarly, the Agricultural Parties support a volumetric return to all customers designated in § 748.5(a) with a prioritization on costs associated with the Cap-and-Trade program itself. The Agricultural Parties argue that customers on agricultural tariffs can be granted relief under § 748.5 as either EITE or small business customers, and they suggest that remaining revenue in each year, if any exists, should first be set aside until a 5% reserve margin has been achieved before additional revenues are returned or used for other purposes such as energy efficiency. The purpose of the reserve margin is to protect covered ratepayers, in the event that in any given year GHG costs exceed revenues, to ensure that ratepayers will be fully compensated for their GHG costs.

4.1.1.1. DA/CCA

17 CCR § 95892(d)(4) requires that investor-owned utilities ensure equal treatment of their own customers and customers of Electricity Service Providers (DA customers) and CCAs. Under the GHG allowance distribution mechanism adopted by ARB, the investor-owned utilities will receive GHG allowances, and therefore allowance revenues, on behalf of both their bundled customers and customers taking generation service from an alternative supplier, namely DA and CCA customers. DA and CCA customer representatives generally support the concept of a volumetric return as proposed in the Joint Utilities' proposal, but

the primary interest of DA and CCA parties in this proceeding is to ensure the equitable treatment of DA and CCA customers under any GHG revenue allocation methodology.

DACC initially supported the allocation of 100% of the GHG allowance revenues to all customers through a delivery rate credit to the customer's distribution or transmission charges, as applicable, in direct proportion to costs (a volumetric return).⁴⁵ However, DACC takes a restrictive view of § 748.5 and revised its proposal in response to SB 1018 to state that only residential, small business and EITE customers should receive a direct volumetric return of GHG allowances revenues. To return revenues to DA and CCA customers, DACC proposes that the revenues be distributed via delivery rates using the generation allocator because GHG costs are recovered in the generation costs charged to customers – either the generation rate for bundled customers or generation charges to DA customers from their electric service providers.

Similar to DACC, CCSF and MEA are principally concerned with ensuring that any allocation of revenues provided to the investor-owned utilities on behalf of their distribution customers is made in a way that ensures that all distribution customers, including customers of CCAs, receive their fair share of those revenues. CCSF and MEA are concerned that the proposal of the Joint Utilities may create a competitive disadvantage for CCA service relative to utility service for lower-tier residential customers. To remedy this situation, MEA proposes (and CCSF supports) that all customers in each customer class be treated the same on a per kWh basis. Specifically, costs for each class would be determined,

⁴⁵ DACC notes in its proposal that some retail customers are connected at transmission-level voltages; therefore, a distribution-only rate credit would be inappropriate.

and within those rate classes, each customer would receive the same per kWh credit as each other customer in that class. MEA states that this approach is consistent with the generally used rate design process in which revenue requirements are attributed to each customer class, and then within those classes, rates are designed to recover the revenue requirements from ratepayers. Similarly, under MEA's plan, when GHG compliance costs are added to the revenue requirement, the entire customer class's rate design would be impacted.

4.1.2. Return GHG Allowance Revenues On A Non-Volumetric Basis (On- or Off-Bill)

The Joint Parties recommend that revenues be used to compensate EITE and small business customers as well as for investments in clean energy or energy efficiency. The Joint Parties propose that any GHG revenues remaining after these actions be returned to all residential ratepayers, including residential ratepayers with usage in Tiers 1 and 2, in the form of an off-bill rebate. According to the Joint Parties, the purpose of including all residential ratepayers, even those without GHG costs included in their rates (Tiers 1 and 2 customers) is to mitigate both the direct and indirect costs associated with the Cap-and-Trade program. The Joint Parties consider "indirect costs" to be costs associated with the increased price of goods and services as a result of the Cap-and-Trade program that are passed on to all residential ratepayers. To the extent possible, the Joint Parties propose that rebates be provided to residential customers in advance of any rate increases. In order to determine the rebate amount per household, the Joint Parties propose that the Commission adopt a methodology to ensure that households that experience higher bill impacts (e.g. households in certain climate zones, with electric heat sources, etc.) receive proportionally larger refunds. SEIA supports the methodology proposed by Joint Parties for the return of GHG allowance revenues to residential ratepayers but differs in its proposal for how to

invest funds in clean energy or energy efficiency, which include investment in infrastructure for renewable energy and creation of a financing mechanism for clean energy projects.

DRA, as mentioned above, suggests that all remaining available revenues after volumetric return of revenues to EITE, small business and residential customers be distributed on an equal per-residential-account basis as an off-bill credit. TURN⁴⁶ proposes that GHG allowance revenues be returned to each residential customer as a separate bill credit (not a reduction to rates), on a uniform cents-per-kWh basis, to ensure that the credit does not interfere with the conservation signals provided by the tiered rate structure. TURN asserts that such a structure would promote customer awareness that the GHG regulation, in addition to sending a carbon price signal, can be a source of revenues to offset costs. Finally, TURN suggests that a small portion of allowance value could be dedicated to providing relief to eligible low-income households for the higher costs of essential consumer goods due to the inclusions of GHG costs in electricity rates, but TURN does not specify any particular percentage of revenues to be used in this way.

4.2. Proposed Methodologies for Investment of GHG Allowance Revenues in Clean Energy and/or Energy Efficiency Programs

Section 748.5(c) permits the Commission to allocate up to 15% of allowance revenue, including accrued interest, for clean energy and energy efficiency projects established pursuant to statute and not otherwise funded. Several

⁴⁶ TURN declined to revise its proposal after the adoption of SB 1018, so its proposal does not take into account the provisions of SB 1018. Because of this, TURN's recommendation is not consistent with the requirements of SB 1018 in that it recommends that GHG allowance revenue be returned only to residential ratepayers.

parties submitted proposals that support the use of a portion of GHG allowance revenues for investment in energy efficiency and clean energy in addition to (and often before) any direct return to customers. Initial proposals differed in the amount of revenues recommended for investment in clean energy and energy efficiency (with amounts often greater than the 15% cap contained in § 748.5(c)) and also in the types of energy efficiency and clean energy programs that should be funded. Proposals range from expanding current energy efficiency programs to providing money to renewable energy developers to mitigate the costs of interconnection with the electric power grid.

Updated proposals filed in response to SB 1018 generally reflect that the maximum amount allowed in that legislation, 15% of revenues, should be allocated toward such programs (unless otherwise noted below). These updated proposals reflect different interpretations of the language of § 748.5(c) limiting GHG revenue allocation to projects that are established pursuant to statute and not otherwise funded by another funding source. For example, DRA initially proposed creation of a Consolidated Financing Program for energy efficiency, but after the passage of SB 1018 it rescinded its proposal as (in its view) not meeting the requirements of § 748.5(c).

4.2.1. Investment to Overcome Market Barriers to Carbon Mitigation Technologies

The Joint Parties propose that the Commission invest a portion of the total GHG allowance revenues in carbon mitigation programs and technologies in order to overcome existing market barriers to entry and/or expansion. The Joint Parties recommend that the Commission prioritize investment in three main categories: (1) expanding energy efficiency programs beyond the Commission's current portfolio, including developing innovative financing strategies to support emerging clean energy technologies and implementation strategies,

(2) expanding low and moderate energy efficiency programs, and (3) enabling better interconnection, integration and support for distributed renewable generation. The Joint Parties propose that funding should be made available to all utility customers, including DA, CCA, and commercial/industrial customers, and that funding should be made available in collaboration with local governments and community-based organizations. The Joint Parties assert that all of these activities are permitted under § 748.5(c).

The Agricultural Parties propose that any remaining funds after compensation of EITE, small business (inclusive of agriculture) and residential ratepayers be invested in cost-effective GHG reduction measures that could be used by the agricultural and food processing sectors. Their suggestions for such measures include conversions of pumping engines powered by diesel and other relatively carbon-intensive fuels to cleaner electric pumps. In addition, the Agricultural Parties recommend directing funds towards low-income energy efficiency programs, renewable distributed generation, and other energy efficiency programs.

The Large Users support investment in low-income energy efficiency programs should any funds remain after GHG allowance revenues covering Cap-and-Trade program costs are distributed to covered classes in § 748.5(a). GPI suggests that the full 15% provided for in § 748.5(c) should be allocated toward clean energy and energy efficiency. One possible use of the funds, GPI suggests, would be to create incentives for biomass in California. IEP, in comments, makes a similar proposal. SEIA suggests that the Commission allocate 5% of GHG allowance revenues for distribution system upgrades associated with the interconnection of renewable projects.

4.3. Customer Education

Section 748.5(b) requires the adoption and implementation of a customer education program to maximize public awareness of the distribution of GHG allowance revenues to ratepayers. Several parties' proposals address the importance of customer outreach and education regarding climate change and the Cap-and-Trade system. The Joint Utilities state that an essential element of GHG allowance revenue return is a well-defined and targeted customer outreach plan. The Joint Utilities argue that each utility should be able to administer its own education program, and the program should provide consistent and objective information to customers using existing communication channels. The Joint Utilities recommend tailoring education and outreach efforts to the characteristics of customers in each service area, and such efforts should be consistent with related programs (e.g. energy efficiency). The Joint Utilities suggest that any education program should be low cost with modest goals and should be funded by GHG allowance revenues.

DRA suggests that customer outreach could include bill inserts, information on utility websites, and information conveyed through media outlets. DRA advocates for separate line-items on bills showing GHG costs and GHG Cap-and Trade Program revenue credits in an effort to facilitate customer understanding of the impact of GHG on customer bills. Like the Joint Utilities, DRA argues that Cap-and Trade program allowance revenues should be used to fund customer outreach efforts (a position also supported by DACC and the Agricultural Parties). DRA recommends that the utilities be ordered to file advice letters for approval showing the exact information that will be conveyed to customers under the outreach and education program adopted consistent with SB 1018. Like most other parties, the Joint Parties support customer outreach

that achieves a wide understanding of and engagement in the GHG allowance revenue allocation program. In contrast to other parties, including the Joint Utilities, the Joint Parties argue that providing an on-bill credit without creating the opportunity to apply the credit to other uses, such as energy efficiency, will make measurement of customer awareness difficult.

MEA argues that outreach and education should be competitively neutral and should be administered by a third-party. MEA asserts that utility administration of outreach programs could result in benefits to the utilities if customers associate the significant monetary benefits from Cap-and-Trade revenues with utility branding and marketing. DACC argues that DA customers have no need for educational programs and do not wish to pay for them because DA customers procure power from energy service providers, all of which bill their customers for their procurement costs. DACC states that GHG costs are directly linked to procurement costs and the load-serving entity billing for the procurement costs should be responsible for educating the customer to the extent that any education is needed. PacifiCorp advocates that it should be responsible for its own customer education efforts, and Bear Valley argues that customer outreach would not be cost effective given the relatively small amount of GHG allowance revenues Bear Valley will receive.

4.4. Emissions-Intensive and Trade-Exposed (EITE)

As noted in Section 3.2.3 above, § 748.5(a) requires the direct return of GHG allowance revenue to EITE customers but does not provide a definition for “EITE.” ARB has designated certain categories of customers as qualifying for Industry Assistance because they are emissions-intensive and trade-exposed, and ARB has established methodologies to provide compensation to address direct emissions costs. ARB provides this compensation to provide transitional

assistance to minimize leakage. ARB has not, however, addressed the provision of relief to those entities for their indirect emissions costs resulting from the increased price of electricity due to the Cap-and-Trade program. Most parties (e.g. the Joint Utilities, the Joint Parties, the Large Users, Tesoro) agree that any distribution of GHG allowance revenue to EITE customers by this Commission should, at a minimum, include those entities qualifying for Industry Assistance under the Cap-and-Trade regulation. However, several parties, including the Large Users and the Agricultural Parties, argue that the EITE designation should be more broadly defined to include industries that, although perhaps not facing substantial direct emissions costs, may be electricity intensive and thus pose a leakage risk due to increased electricity costs resulting from Cap-and-Trade. The Joint Utilities argue that EITE should be even more broadly defined to include all non-residential, private sector electric customers that compete with entities outside of California.

Outside of a volumetric return proposed by many parties (the Joint Utilities, DRA, DACC, MEA, etc.), we received several additional GHG allowance revenue allocation methodologies for EITE customers. The Large Users propose three options for returning GHG allowance revenue to EITE customers, which they argue should be the first priority before distributing revenue to other customers. Option A provides that allowances would shift from the utility allocation back to ARB before they are monetized to permit ARB to integrate the allowances attributable to EITE utility ratepayers into its benchmarking and allocation process. Option B provides for the allocation of the full value of monetized utility allowances to all ratepayers, based on energy usage, but creates a priority allocation for EITE customers. Option C provides that the Commission establish its own benchmarking methodologies for indirect

electricity emissions attributable to EITE customers, complementing ARB's benchmarks for direct emissions from Industrial Covered Entities.⁴⁷ Specific step-by-step methodologies for implementing each of the options are detailed in the Large Users' proposal.

The Joint Parties propose that EITE customers receive allowance revenues based on a formula that accounts for EITE customers' historical consumption, leakage assistance factors in ARB's Cap-and-Trade regulation, and incremental rate impacts forecast by the utilities on the customer class to which each EITE belongs. For DA customers that are classified as EITE, the Joint Parties propose the Commission apply the same formula as to bundled EITE customers. The Joint Parties argue that by relying on historical usage patterns, the proposed methodology will retain strong incentives for EITE customers to maximize efficient electricity consumption.

4.5. Combined Heat and Power (CHP)

CHP resources produce three main products: 1) wholesale electricity exported to the grid, 2) retail power consumed on-site or by over-the-fence customers, and 3) thermal energy consumed on-site or by over-the fence customers. Proposals addressing CHP focus primarily on ways to ensure that CHP is not placed at a disadvantage compared to utility customers as a result of the Cap-and-Trade program. The CHP proposals emphasize that avoiding such disadvantages is particularly important to the extent that its deployment is net-GHG-reducing as compared to separate heat and power. In general, if electricity rates reflect the costs of the Cap-and-Trade program, the host customer can

⁴⁷ See 17 CCR § 95891 for details on ARB's benchmarking process for Industrial Covered Entities.

reduce its GHG compliance burden through the deployment of efficient CHP; in other words, when electricity rates reflect Cap-and-Trade costs, the proper economic signals for CHP will be present.

If rates do not reflect GHG costs, for example if the GHG allowance revenues are returned volumetrically to offset GHG costs, CHP could be placed at an economic disadvantage compared to separate heat and power, even if it is highly efficient and net-GHG-reducing. This perverse outcome would occur because the CHP facility would face a GHG compliance obligation (assuming it meets or exceeds the 25,000 MTCO₂e compliance threshold) for all of its emissions associated with the production of both thermal energy and electricity whereas a customer that purchases electricity from the grid and produces thermal energy separately from a standalone boiler would only bear GHG costs associated with the production of thermal energy. This issue is further complicated because some CHP resources are deployed by, or sell to, entities that have been designated as requiring Industry Assistance by ARB. Industry Assistance status and ownership structure affect the amount of free allowances distributed to the CHP unit's host customer.

4.5.1. CHP Proposals

The Large Users seek to ensure that any allowance revenue methodology adopted by the Commission mitigates leakage risk. As described above, they presented three options for achieving this. Under Option A, by including all direct and indirect emissions in ARB's methodology to allocate allowances, irrespective of whether a facility that qualifies for transition assistance receives its power from onsite generation, via a third party provider, or from an incumbent utility, incentives to invest in clean CHP would be preserved. The Large Users' Option B would return revenues (rather than returning allowances)

volumetrically to all customers, but would make the return “portable.” The Large Users define portability as allowing entities that deploy onsite generation to continue to receive allowance value commensurate with the amount of electricity they generate onsite. The Large Users explain that the initial utility allowance allocation was based on the utilities’ 2008 load and GHG emissions. Therefore, if an EITE consumer leaves the grid post-2008 and installs CHP, a proportionate share of the allowance revenue should follow that customer to cover its additional emissions costs because the emissions are no longer associated with power from the grid but with that CHP unit.

Finally, under Option C, the Commission would adopt its own indirect electricity emissions benchmarking methodologies that function in parallel with ARB’s methodologies to provide Industry Assistance. The allocations resulting from these benchmarks would direct GHG revenues to EITE entities, including those that rely on self-generation. The Large Users argue that such an approach would preserve appropriate incentives for CHP, maintain an incremental carbon price signal in rates, and reduce leakage risk. The Large Users also provide variations of this approach to preserve appropriate incentives for CHP in the refining sector.

CCC offers several possible solutions the Commission could consider, depending upon the overall revenue allocation methodology adopted. As CCC discusses, under ARB’s adopted allowance allocation methodology, because CHP units do not directly receive freely allocated allowances, the investor-owned utilities will receive allowances associated with the retail electricity provided by CHP units in their respective service territories. CCC argues that if the Commission were to adopt the Joint Utilities’ proposal, GHG allowance revenues would be returned to customers based on customers’ current

usage, which would result in the carbon price signal not being fully reflected in retail rates. Under this scenario, CCC recommends that the Commission direct each investor-owned utility to allocate a proportionate share of the GHG allowance revenues to the retail customer(s)/host(s) of CHP facilities in its service territory in proportion to the amount of retail load served by the CHP facility. To achieve the proper allocation of revenues to CHP facilities and/or their hosts, CCC suggests that the customer-host for the CHP facility receive GHG allowance value based upon its standby purchases from the utility and its on-site retail purchases from the CHP facility. CCC suggests that information on such on-site retail purchases from the CHP facility is available to the utility via the Qualifying Facility Efficiency Monitoring program. CCC also offers a methodology to avoid double counting by customers receiving Industry Assistance by ARB.

4.5.1.1. Third-Party CHP

Tesoro raises concerns regarding the lack of Industry Assistance provided to refineries for the GHG costs of electricity purchased from third-party CHP and suggests that the Commission could provide such assistance in this decision. Tesoro supports CCC's proposal generally but argues that while CCC's proposal addresses the potential for stranded costs for third-party owned CHP, it does not adequately address the need for EITE assistance for power purchased from third-party CHP. In particular, Tesoro submits its proposal on behalf of its Golden Eagle Refinery,⁴⁸ which purchases power from a CHP unit that is owned by a third party. Tesoro has no ownership interest in the CHP unit. As an entity receiving Industry Assistance, Golden Eagle will receive freely allocated

⁴⁸ Petroleum refining is classified by ARB as requiring Industry Assistance.

allowances based upon its baseline annual GHG emissions. The emissions of the third-party CHP unit are not part of this baseline, and the independent CHP unit is not itself eligible for Industry Assistance; thus, Tesoro will receive no Industry Assistance for the GHG costs associated with the electricity it purchases from the third-party CHP unit. However, if the CHP unit and refinery were under common ownership, allowances would be freely allocated in proportion to the emissions of the CHP unit. Tesoro asserts that this differential outcome results in a significant competitive disadvantage for Tesoro and any other similarly situated entities and creates a market disincentive to purchase power from third-party owned CHP.

To address this adverse impact, Tesoro proposes that the Commission direct the utilities to set aside revenues from the auction of GHG allowances to compensate customers of third-party-owned CHP for the purchase of allowances required to cover emissions associated with power purchased from such CHP generators. Tesoro proposes a methodology for calculating the set-aside in Exhibit A of its proposal. Alternatively, if the Commission does not provide for a set-aside of auction revenues, Tesoro requests that the Commission formally recommend that ARB revisit and revise the Industry Assistance allocation methodology and account for emissions associated with power purchased from third-party-owned CHP.

4.6. Small and Multi-Jurisdictional Utilities

At this time, three small and/or multi-jurisdictional electric utilities operate within the state of California and receive Cap-and-Trade allowance allocations from ARB. These utilities are PacifiCorp, Bear Valley, and CalPeco.

PacifiCorp is California's sole multi-jurisdictional utility under Commission jurisdiction, providing service to more than 1.6 million customers in

six western states (California, Idaho, Oregon, Utah, Washington, and Wyoming). PacifiCorp primarily serves rural communities in California, and its 41,000 California customers represent approximately 2% of the company's total electric load. Many of PacifiCorp's California customers are eligible for its low-income assistance program. PacifiCorp is uniquely situated because it has load service in multiple states and therefore has multi-state cost allocation considerations.

CalPeco is a small investor-owned utility that serves approximately 49,000 customers, most in rural and resort areas. CalPeco's residential customers, many of whom have only second or vacation homes in the area, account for about half of the company's electric load, and most of the rest of the load is associated with ski resorts and related facilities. Bear Valley is a small electric utility company that serves approximately 23,000 customers in the Big Bear recreational area within the San Bernardino Mountains. Of Bear Valley's customers, the vast majority are residential, and most are not full-time residents of the area.

In comparison with PG&E, SCE and SDG&E, these utilities have relatively small service territories and, importantly, are not subject to the statutory limitations on lower-tier (Tiers 1 and 2) residential rate adjustments imposed by SB 695. Thus, GHG costs can be fully reflected in Tier 1 and 2 residential rates. All three utilities will receive relatively small numbers of freely-allocated GHG allowances under ARB's Cap-and-Trade regulation, consistent with their small shares of California's electric load. Bear Valley in particular will receive an extremely small amount of allowances.

4.6.1. Small and Multi-jurisdictional Companies' Proposals for Use of Allowance Revenue

The guiding principle behind PacifiCorp's proposal is ensuring sufficient flexibility to use revenues in a way that makes sense given its circumstances as a multi-jurisdictional, vertically integrated utility. PacifiCorp also states that its customers are not neatly divided into residential, commercial, and industrial classes in the same manner as the customers of the larger utilities. PacifiCorp acknowledges, however, that it would not be particularly administratively burdensome or costly for PacifiCorp to return revenues directly to customers on their bills, as long as the return amount is the same or calculated similarly for all customers on a particular rate schedule. PacifiCorp also notes that it does not classify industrial customers by industry type, thus returning allowance revenue to EITE customers would prove difficult. As such, PacifiCorp suggests that customers be allowed to self-identify as EITE, if necessary, based upon criteria adopted in this decision.

CalPeco proposes using its allowance revenues to offset any administrative costs imposed by the Cap-and-Trade program along with any increase in its purchased power costs due to the program. Under CalPeco's proposal, any residual allowance revenues would be distributed to its customers on a volumetric basis through its Energy Cost Adjustment Clause mechanism, which is roughly equivalent to the large utilities' ERRRA proceedings.

Bear Valley is unique in that it will receive an almost negligible amount of GHG allowance revenues. If the allowance price reaches \$20, almost twice the floor price specified in the Cap-and-Trade regulation, Bear Valley will receive a total of about \$1,200 in Cap-and-Trade allowance revenues each year. Bear Valley also notes that any administrative expenses required to implement a new program, or even to institute new tracking or reporting requirements, are likely

to exceed their annual allowance revenues. Bear Valley proposes to return allowance revenues on a volumetric basis to all of its customers through its Purchase Power Adjustment Clause proceeding, which is roughly equivalent to the large utilities' ERRRA proceedings.

4.7. BART

BART, a local government agency providing public transit services in the San Francisco Bay Area through the operation of an electric railway system, currently purchases federal preference power and power from local publicly owned utilities that is delivered to BART by PG&E under special terms and conditions codified in § 701.8. In opening comments,⁴⁹ BART offered general support for the Joint Utilities' proposal; however BART is concerned that the Joint Utilities' methodology for distribution of GHG allowance revenues may not fully compensate BART for its GHG costs.

Under the Joint Utilities' proposal, BART is considered to be a retail customer of PG&E and will receive GHG allowance revenue accordingly. However, the allowances allocated to PG&E by ARB reflect PG&E's specific resource mix, which BART calculates to be around 643 pounds of CO₂ emissions per MWh. BART, because it purchases power from sources other than PG&E (including unspecified imported power), will be assessed a carbon compliance obligation of approximately 877 pounds of CO₂ emissions per MWh. Therefore, GHG allowance value received from PG&E will not cover the entirety of BART's compliance obligation. Furthermore, BART expects its electric load to increase

⁴⁹ BART did not submit a formal opening or revised proposal; however, BART's opening comments contained what amounts to a proposal for specific allocation of GHG allowance revenue to BART. Because parties had an opportunity to respond to BART's proposal in reply comments, we consider it as a proposal in this proceeding.

significantly during the ARB compliance periods, which will result in an increasing disparity between compliance expense and cost recovery. To remedy this situation, BART proposes that the Commission require PG&E to allocate to BART an amount from GHG allowance revenues sufficient to offset BART's increased cost of electricity purchases due to its Cap-and-Trade compliance obligation.

5. Discussion

5.1. Summary

In accordance with § 748.5, AB 32, and other applicable statutes and regulations, this decision adopts a methodology for allocating GHG allowance revenues received by California's investor-owned utilities, including small and multi-jurisdictional utilities, as part of the Cap-and-Trade program. The three large investor-owned utilities, PG&E, SCE, and SDG&E, are directed to allocate GHG allowance revenues, including accrued interest, in the following manner (and in the following order of priority):

1. Compensate emissions-intensive and trade-exposed entities (as defined in this decision) using methodologies based upon those developed by ARB to address direct emissions cost exposure under the Cap-and-Trade program;
2. Offset the rate impacts of the Cap-and-Trade program in the electricity rates of small businesses, defined as entities with monthly demand not in excess of 20 kW in more than three months within a 12-month period, through a volumetrically calculated rate adjustment;
3. Given the disproportionate cost burden currently reflected in upper-tier residential rates and the limited ability to pass Cap-and-Trade costs through to residential customers on the basis of cost responsibility, neutralize the rate impacts of the Cap-and-Trade program on residential electricity rates through a volumetrically calculated rate adjustment.

4. Distribute all revenues remaining after accounting for the revenues allocated pursuant to the prior three uses to residential customers on an equal per residential account basis delivered as a semi-annual, on-bill credit.

PacifiCorp and CalPeco are directed to return revenues according to the process set forth above with one exception. Because PacifiCorp and CalPeco are statutorily able to allow all residential rates (including lower-tier rates) to rise to reflect the price of carbon, no one class of residential ratepayers will bear disproportionate GHG costs in relation to any other class. Therefore, PacifiCorp and CalPeco shall return all remaining GHG allowance revenues, after compensating emissions-intensive and trade-exposed entities and small businesses, directly to their residential ratepayers on a per residential account basis delivered semi-annually via an on-bill credit (thus skipping Step 3, above). Bear Valley, as a small utility receiving minimal GHG allowance revenue, is ordered to return 100% of its GHG allowance revenue in direct proportion to costs borne by its customers (a volumetric return) through its existing, annual Purchase Power Adjustment Clause proceeding.

Investor-owned utilities are directed to allocate GHG allowance revenues to all customers in the applicable customer groups set forth in this decision inclusive of DA and CCA customers in a competitively neutral manner as required by the Cap-and-Trade regulation. CCA and DA customers shall receive their proportional share of GHG revenues, and such revenues shall be dispersed according to the methodology set forth above.

The GHG revenue allocation methodology adopted in this decision requires additional record and development before it can be finalized and implemented. If GHG-related energy costs were immediately recoverable in rates before the GHG revenue allocation methodology is implemented, retail

customers eligible to receive GHG allowance revenues would see only the cost increase without any countervailing revenues. Therefore, we defer including in rates GHG costs and revenues for all retail customers until necessary implementation details are resolved.

We decline, at this time, to allocate any portion of GHG allowance revenues toward clean energy or energy efficiency measures, preferring to focus our initial efforts on maximizing the amount of revenues returned directly to residential ratepayers (after returning revenues to emissions-intensive and trade-exposed and small business ratepayers). We take this approach to mitigate the increased cost of goods and services that will be ultimately borne by residential ratepayers as businesses pass on the carbon cost embedded in their electricity rates. We do, however, set forth high-level guidelines to be considered if the Commission decides at a later date to direct some portion of GHG allowance revenue toward clean energy or energy efficiency measures. In that event, we believe that the appropriate venue to consider the type of clean energy or energy efficiency programs or projects that could be funded GHG allowance revenue is within those respective proceedings.

This decision also adopts a competitively neutral interim customer education and outreach plan for 2013 administered by the investor-owned utilities on behalf of all customers, including customers of Electric Service Providers and CCAs, and adopts a process to develop a more comprehensive and robust customer outreach and education plan for 2014 and beyond.

We note that this decision reflects our judgment based on the record before us at this time, in advance of full implementation of the Cap-and-Trade program. We will monitor the impacts of Cap-and-Trade on electricity customers, and, if appropriate, we may adjust the GHG allowance return methodology adopted

today. We also encourage a similar evaluation by ARB to monitor the impacts of the Cap-and-Trade regulation and reevaluate their treatment of particularly vulnerable entities, if necessary.

5.2. Policy Objectives

To help inform the development of party proposals addressing the use of GHG allowance revenues, as well as the Commission's evaluation of those proposals, the September 1, 2011 *Assigned Commissioner and Administrative Law Judges' Scoping Memo and Ruling* proposed seven key policy objectives against which proposals could be assessed. Those objectives were drawn from policy objectives developed both by the Commission and by other entities focusing on AB 32 implementation, such as ARB's Economic and Allocation Advisory Committee. The objectives were refined through feedback received during an August 1, 2011 workshop, in which parties discussed an initial set of policy objectives proposed in an ALJ Ruling issued in July 2011. The scoping memo also encouraged parties to suggest alternative or additional policy objectives beyond those enumerated and to suggest a ranking of the objectives in their proposals. The seven proposed policy objectives are listed below:

1) Preserve the Carbon Price Signal

Preservation of the carbon price signal refers to the extent to which, under a given proposal, the cost of compliance with the Cap-and-Trade program is reflected in electricity rates after any allowance revenue is distributed. Retaining this price signal ensures that retail electricity customers bear the costs to society of the carbon emissions resulting from the production of electricity and make consumption choices accordingly.

2) Prevent Economic Leakage

Prevention of economic leakage addresses the unique concerns of entities that, absent assistance, are at risk of

shifting production to jurisdictions outside of California, which results in a shift, rather than a reduction, in GHG emissions along with a loss of economic activity within California.

3) Distribute Revenues Equitably Recognizing the Public Asset Nature of the Atmospheric Carbon Sink

The equitable distribution of revenues recognizing the “public asset” nature of the atmospheric carbon sink refers to the extent to which revenues are distributed consistent with the idea that the atmosphere is a commons to which all individuals have an equal claim.

4) Reduce Adverse Impacts on Low Income Households

Reduction of adverse outcomes to low-income households refers to a given proposal’s recognition of the potentially disproportionate impact of the Cap-and-Trade program in terms of direct and indirect costs borne by low-income households as a share of total household income. Additionally, this objective includes consideration of the potentially disproportionate impacts on low income households and communities resulting from climate change itself, given the relatively limited capacity these households and communities may have to adapt to changing climatic conditions and associated environmental, economic and public health effects.

5) Correct for Market Failures that Lead to Underinvestment in Carbon Mitigation Activities and Technologies

Correction of market failures that lead to ongoing underinvestment in carbon mitigation activities and technologies refers to the degree to which the proposed use of auction revenues addresses market failures that are likely to continue to inhibit or prevent investment in carbon mitigation activities and technologies, despite the inclusion of carbon costs in energy prices.

6) Maintain Competitive Neutrality Across Load Serving Entities

Proposals that maintain competitive neutrality across load serving entities ensure that the relative competitive position of different entities that provide retail electric service, including regulated electric distribution utilities, Electric Service Providers, and CCAs, is unaffected by the adopted GHG revenue allocation methodology.

7) Achieve Administrative Simplicity and Understandability

Achievement of administrative simplicity and understandability refers to the relative simplicity of a given proposal from the standpoint of implementation, as well as the ability of consumers to comprehend the approach being proposed.

Parties proposed several additional policy objectives for consideration, and provided a variety of opinions on the relative importance of the objectives. Many of the policy objectives proposed by parties appeared to support those parties' initial proposals for GHG allowance revenue distribution methodologies. However, the passage of SB 1018 resulted in the modification of proposals by several parties and the nullification of many elements contained in proposals, which in many cases affects the appropriateness of applying the different policy objectives. For this reason, we will simply list the policy objectives proposed by parties and provide a brief description of each.

The Agricultural Parties propose that the Commission adopt a policy objective to ensure that GHG allowance revenues are returned to ratepayers only in proportion to their Cap-and-Trade costs, rather than returning all revenues (inclusive of those that are earned as a result of the conveyance of allowances by ARB to the utilities in recognition of early actions taken toward achieving GHG

reductions) to offset costs above and beyond those imposed by Cap-and-Trade. The Joint Utilities and Large Users suggest an objective to mitigate customer cost increases due to both the Cap-and-Trade program and other AB 32 emissions reductions, such as energy efficiency and renewable energy costs. However, parties in support of this proposed objective do not necessarily agree that a volumetric return to ratepayers, as proposed by the Joint Utilities, is the most appropriate allocation methodology. The Large Users propose two additional policy objectives: (1) prevent underinvestment in CHP resources, and (2) ensure that indirect GHG costs arising from an EITE ratepayer's purchases of electricity from the grid are mitigated, in order to minimize economic leakage. The second recommended policy objective can be seen as a refinement of the Commissions' proposed objective to minimize economic leakage in that it specifically mentions indirect electricity costs borne by EITE ratepayers. GPI proposes that we adopt a policy objective to direct sufficient revenue toward energy efficiency and the Renewables Portfolio Standard program to assist in achieving programmatic targets. Finally, DRA and the Joint Parties suggested that the Commission adopt a policy objective to educate customers about the impacts and benefits of the Cap-and-Trade program.

5.2.1. Parties' Analysis of Policy Objectives

Included in their initial proposals, parties provided their thoughts on the relative importance of the various policy objectives; however, it is impossible to develop a rank ordering for the objectives among parties because parties addressed the policy objectives in diverse ways. For example, some parties provided a clear rank ordering while other chose to comment on only a subset of the policy objectives but did not provide an overall ranking of their importance. Furthermore, parties interpreted the terminology of some objectives differently,

which impacts the overall importance of the objective to those parties. For example, the utilities propose an objective that revenues be “equitably” distributed.⁵⁰ The utilities define equity in this context as ensuring that revenues are returned to ratepayers in a manner consistent with cost causation principles and avoiding cross-subsidies between customer classes. The word equitable is generally defined to mean “fair,” and, depending on a party’s goals, fairness or “equity” could be defined differently. Therefore, rather than setting forth a specific ranking of objectives by parties, we highlight those objectives described as most important to parties. Finally, it is important to note that parties’ positions on policy objectives were formulated prior to the passage of SB 1018. Thus, the importance placed on the various policy objectives by parties may not comport with the provisions of § 748.5 or updated proposals filed by those parties after passage of SB 1018.

The Large Users, the Joint Agricultural Parties, and DRA all argue that it is important to mitigate or, if possible, fully offset customer rate increases resulting from procurement-related GHG costs. All three parties argue that this policy objective will ensure that funds are used for the benefit of customers by ensuring that the benefits from the Cap-and-Trade program are distributed in proportion to the costs associated with the program. The Joint Utilities argue that one of the most critical policy objectives is to return revenue to customers in a manner “consistent with the principles of cost causation.”⁵¹

In addition to this primary objective, the Joint Utilities also suggest a compound objective of mitigating cost increases for all consumers, ensuring cost-

⁵⁰ Joint Utilities Proposal filed October 5, 2012 at 7.

⁵¹ Joint Utilities Revised Proposals, January 6, 2012 at 11.

effectiveness of emissions reduction measures, and reducing adverse impacts on low-income households. Also listed as important are administrative simplicity and understandability, maintaining competitive neutrality and preventing economic leakage. The Joint Utilities argue that it is not necessary to preserve the carbon price signal from the implementation of Cap-and-Trade in rates for several reasons. Among these reasons, they assert that all customers already see a carbon price signal due to the existence of the energy efficiency and Renewables Portfolio Standard, and all upper-tier residential rates already include costs in excess of those they would otherwise see inclusive of only the GHG costs associated with upper-tier usage.

For DACC, priority policy objectives are maintaining competitive neutrality across load-serving entities and achieving administrative simplicity. DACC argues that maintaining competitive neutrality is necessary to ensure that the investor-owned utilities do not benefit disproportionately or unfairly from GHG revenues compared to Electric Service Providers and CCAs, and administrative simplicity will ensure that any distribution plan can be easily implemented and understood by customers. Similarly, the Agricultural Parties support the policy objective of administrative simplicity. In addition, the Agricultural Parties and the Large Users consider prevention of economic leakage to be a vital policy objective. The Large Users also argue that prevention of underinvestment in CHP resources should be a priority of this Commission.

SEIA ranks preservation of the carbon signal as its top objective, followed by correcting for market failures that lead to underinvestment in carbon mitigation activities and technologies. SEIA suggests that this latter objective will ensure that customers have avenues for responding to any price signals generated by Cap-and-Trade or other programs. Also of importance to SEIA is

prevention of economic leakage and reduction of adverse impacts on low-income households. SEIA suggests that the existing tiered rate structure combined with the CARE low-income assistance program effectively shields low-income customers from most cost increases. Based on this concept, SEIA argues that the Commission should focus on providing low-income customers with options for reducing their energy costs, rather than focusing on reducing low-income customers' rates.

Rather than ranking the policy objectives, the Joint Parties suggest that the Commission should evaluate proposals according to all of the objectives suggested in the scoping memo for this proceeding, along with a new objective that they propose. This new objective, which is also proposed by DRA, is the facilitation of customers' understanding of and support for California's climate change programs. The Joint Parties recommend that the Commission should prioritize proposals that advance the most policy objectives, rather than focusing on one or a few key objectives to the exclusion of others.

PacifiCorp suggests that reducing adverse impacts for low-income customers, achieving administrative simplicity, and correcting for market failures that lead to ongoing underinvestment in carbon mitigation activities are the most important policy objectives. Other parties, including GPI and MEA, do not explicitly rank or discuss the relative importance of the policy objectives suggested by the Commission, though they refer to some of the objectives that may be advanced through their own proposals.

5.2.2. Discussion on Objectives

We consider all policy objectives in the context of the various regulatory and legislative mandates that set specific requirements for the distribution of GHG allowance revenues, including SB 1018 and the Cap-and-Trade regulation.

For the purposes of this decision, we focus our discussion on the priority of each policy objective as it informs our choice on the appropriate GHG allowance revenue distribution methodology. We rely primarily on the objectives initially proposed by the Commission because the majority of parties' proposed objectives, with one exception, were either developed to support their own GHG allowance revenue distribution methodologies or can be seen as a subset of a Commission proposed objective. The one exception is the objective addressing customer education.

5.2.2.1. Preserve the Carbon Price Signal

We believe that preservation of the carbon price signal is a high priority objective. Indeed, it represents a foundational element of the Cap-and-Trade program that guides our thinking throughout this decision. An efficient allocation of society's scarce resources requires that the price of goods and services reflect the full, social costs of their production. Prior to the implementation of the Cap-and-Trade program, the price of carbon emissions generally has not been reflected in the prices consumers face for goods and services. In order to preserve the incentives the Cap-and-Trade program is intended to provide, the costs of carbon should generally be reflected in the price of electricity so that these costs can, in turn, be appropriately reflected in the price of goods and services that rely on electricity. Absent this, electricity consumption, and consumption of goods and services that use electricity, will be higher than the socially optimal level. Therefore, in considering various ways of using the allowance revenues, we stray from this fundamental objective only in extenuating circumstances where preserving the carbon price signal is impractical or otherwise infeasible. For example, existing Legislative mandates may prevent the Commission from preserving the carbon price signal in all rates

for all customers. In other cases, the administrative burden of maintaining a carbon price signal may be prohibitive. In these cases, where statute or other requirements prevent the Commission from preserving the carbon price signal, we consider allocating GHG revenues in a manner that does not strictly adhere to the objective of maintaining the carbon price signal, recognizing that these approaches are less than ideal and should be revisited should circumstances change.

Viewed through this lens, the Cap-and-Trade regulation is designed to have a twofold impact in the electricity sector: it internalizes the cost of emitting GHG in wholesale electricity prices, thus encouraging the development and dispatch of lower-GHG-emitting electricity generators; and it simultaneously internalizes the cost of emitting GHG into retail electricity rates, absent any countervailing action by this Commission. Just as carbon pricing creates an economic incentive for the wholesale electricity market to reduce its GHG emissions, carbon pricing creates an additional incentive for retail electricity customers to substitute away from energy and/or emissions intensive activities, as well as invest in energy efficiency and other measures that have the effect of reducing their exposure to GHG costs. Carbon pricing creates an economic incentive for market actors – whether wholesale generators or retail ratepayers – to find the most efficient ways to reduce GHG emissions. The efficacy of the regime in encouraging these positive behavioral and economic decisions rests fundamentally on the presence of a carbon price signal.

We note that this is in stark contrast to the position of the Joint Utilities (and effectively SEIA), which argue that the price of electricity is already higher than socially optimal owing to the costs of programs like the Renewables Portfolio Standard, the California Solar Initiative, and ratepayer-funded energy

efficiency programs. Based on this argument, the Joint Utilities suggest the revenues from the sale of allowances should be used to offset the above market costs of these programs in an effort to reduce rates, making them closer to what a more socially optimal level would be. The Joint Utilities also argue that using allowance revenues for this purpose would be consistent with the concept of using the funds to compensate customers for the costs of AB 32, including not only the Cap-and-Trade program itself, but also the various complementary programs that have been identified in the ARB Scoping Plan as contributing to the implementation of AB 32. The Joint Utilities' arguments suggest that from the perspective of economic efficiency, rates should be lower than they currently are to the degree that they are in excess of what would otherwise prevail under the Cap-and-Trade system absent those complementary programs.

At its heart, this line of reasoning suggests that the exclusive purpose of these other programs is to reduce GHG emissions, and the State, by compelling the utilities to use a particular suite of solutions to mitigate GHG emissions, has selected less economic options than what the market would choose absent these regulatory interventions. While GHG mitigation is certainly an objective of these programs, it is by no means the only objective. The benefits of these programs extend beyond energy and GHG benefits and include improved air quality, environmental protection, economic development, and resource diversity and energy security.⁵² Though many of these forgone benefits would not expressly

⁵² For example, § 399.11 which established the 33% renewable energy mandate, identifies various objectives associated with achievement of the state's renewable energy mandates. In addition to reducing GHG emissions, these include displacing fossil fuel consumption, reducing air pollution, and providing resource diversification. § 399.16(f)(7) identifies economic development as well as addressing air quality issues in disadvantaged communities. Section 2827(a) finds that net energy metering, a key

appear in the costs faced by electricity consumers if these programs did not exist, they are costs nonetheless. We believe that relying exclusively on rate comparisons in assessing the effects of these programs leads to conclusions that overstate the relative costs of programs like the Renewables Portfolio Standard, the California Solar Initiative, net energy metering, and energy efficiency given the myriad benefits, beyond GHG emission reductions, these programs provide.

Furthermore, issues of cost containment are best addressed within the context of the various programs themselves and their associated proceedings. For example, the current Renewables Portfolio Standard legislation includes provisions related to cost containment, which the Commission will need to explore. Section 399.15(c) directs the Commission to establish a limitation of procurement expenditures for all eligible renewable resources used to comply with the Renewables Portfolio Standard program. In the case of energy efficiency, the Commission already considers cost-effectiveness in its determinations regarding the amount of funding and types of programs the utilities are authorized to pursue.

We disagree with the argument put forward by various parties, either explicitly or implicitly, that suggests that an equitable approach to allocating the allowance revenues requires giving more of the value to those facing the highest GHG costs and less allowance value to those facing the least GHG costs. This approach to equity, implicit to the various proposals that suggest allocating

element in enabling the economic deployment of customer-side renewable generation, in particular solar, supports economic growth and contributes to resource diversification. Section 399(e)(3) finds that energy efficiency expenditures reduce environmental costs associated with California's electricity consumption including, but not limited to, degradation of the state's air, water, and land resources.

revenues volumetrically, would disproportionately reward high consumption energy users. The Cap-and-Trade system works by attaching a price to emissions and compelling emitters to make an economic decision between reducing emissions and purchasing a compliance instrument to cover their emissions. Emitters that choose to reduce their emissions can then decide whether to do so through the deployment of energy efficiency measures, reduced output, or reliance on less emission intensive sources of energy. These costs of compliance are then passed through to end consumers, who, when confronted by those costs, have the choice to shift toward less emission-intensive activities and consumption patterns. To create a GHG price signal only to offset it through the allocation of allowances would short-circuit the basic economic functioning of this process by preventing producers, and ultimately consumers, from seeing that price signal. This would negate the point of the Cap-and-Trade policy.

The Joint Utilities further argue that even absent a retail price signal, the wholesale markets will still see and respond to the price signal created by the Cap-and-Trade program, causing resource choices, in the form of least cost economic dispatch, to reflect the cost of carbon. While having merit, we believe this argument misses an important point, namely that by using the GHG allowance revenues to reduce retail electricity rates relative to what they would otherwise be, the Joint Utilities' approach represents a subsidy to consumption of grid-based electricity. Such an approach will mute incentives faced by retail customers, who are increasingly viewed as playing a central role in shaping the future of energy in California through the choices they make on the customer side of the meter. Although the Joint Utilities' argue that the price sensitivity of

demand for electricity is highly inelastic,⁵³ such that only very large changes in electricity prices result in significant changes in consumption, we note that a number of parties have argued that a carbon price can materially impact resource choices. The Joint Parties, for example, argue that the Cap-and-Trade program can facilitate changes in consumer behavior over the long run and “elevate the visibility of energy efficiency opportunities...”⁵⁴ Additionally, the parties representing the CHP community have argued that offsetting the price of carbon in grid-based electricity rates will substantially disadvantage CHP resources if their emissions costs are not similarly offset. This would seem to suggest that the carbon price signal can and does materially impact the resource decisions energy consumers make. It is not clear why these same arguments would not similarly affect the willingness of consumers to pursue energy efficiency, distributed generation, or other resource options.

For all of the foregoing reasons we do not, as a general matter, find it reasonable or consistent with the intent of AB 32, including the Cap-and-Trade program, to return allowance revenues in a manner that would mute or otherwise obscure the carbon price signal given the essential role that the price signal plays in achieving GHG reductions under a Cap-and-Trade system. We find that a price signal specifically associated with the cost of emitting GHG emissions, as embodied in the cost of emissions allowances and offsets, should generally be reflected in retail rates. Such a signal can be expected to provide the

⁵³ It is unclear if the price elasticity calculation the Joint Utilities provided in comments represents a short or long-run price elasticity. We agree that short-run demand is likely to be highly inelastic, since modifying energy consumption often requires deploying additional capital and replacing physical assets, which are typically associated with the long-run.

⁵⁴ Reply comments of Joint Parties, February 14, 2012 at 13.

appropriate incentives for conservation, demand response, and energy efficiency, as well as the deployment of clean generation and storage technologies.

However, we do acknowledge that there are instances where a reflection of the carbon price signal in rates, at least initially, may not be optimal and other instances where barriers exist to the full reflection of that signal. As described below, in the case of those industries designated as qualifying for Industry Assistance under the GHG regulation, the risk of emissions and economic leakage requires actions to partially shield certain industries from emissions cost exposure caused by electricity use. Furthermore, residential retail rates, as currently structured, place a disproportionate share of GHG costs on ratepayers paying rates in the upper-tiers while shielding those ratepayers in lower-tiers (representing the majority of load) from seeing any GHG costs.

5.2.2.2. Prevent Economic Leakage (and Emissions Leakage)

Consistent with the policy stance taken by ARB and the presumed intent of the Legislature in SB 1018, we seek to minimize the effects of economic (and emissions) leakage in California as a result of the Cap-and-Trade program. As a result, we consider this policy objective to be a high priority. As discussed earlier, ARB takes a concrete step, in the form of a free allocation of emissions allowances to Industrial Covered Entities that receive Industry Assistance, to ensure that the Cap-and-Trade program does not have the effect of reducing the profitability of California manufacturers and thus preventing them from investing in cost-effective emissions reductions, which could result in those entities shifting their economic activity (and associated emissions) outside of California. As noted earlier, ARB's Industry Assistance allowance allocation methodology addresses GHG costs associated with direct emissions and emissions from steam purchases but stops short of addressing potential cost

exposure from indirect electricity emissions (i.e. from electricity purchases). To the extent that electricity rates reflect Cap-and-Trade costs, these entities will face GHG costs through their electricity purchases. As with the compliance costs associated with direct emissions, for entities operating in trade-exposed sectors, indirect GHG cost exposure creates the risk of both economic and emissions leakage, an outcome that would harm California's economy while doing nothing to reduce GHG emissions globally. ARB's Economic and Allocation Advisory Committee and the parties in this proceeding argue that the cost of compensating industrial entities that qualify for Industry Assistance for their GHG cost exposure from indirect electricity purchases is relatively small, as a fraction of total allowance revenue, and would leave the vast majority of allowance revenue available for other purposes. We also recognize, as discussed earlier in this decision, that there may be other entities that pose leakage risks that are not specifically designated as qualifying for Industry Assistance by ARB, either because these entities emit less than 25,000 MTCO₂e and/or are not covered by the cap and, thus do not have to surrender allowances for their direct emissions.

5.2.2.3. Reduce Adverse Outcomes on Low Income Households

The objective of reducing adverse outcomes to low-income households is consistent with general Commission policy and is particularly relevant in the current economic climate of high unemployment and state budget shortfalls. Therefore, we consider this objective to be a high priority. As reflected in programs such as CARE and Low Income Energy Efficiency, which are available to all households with income under 200% of the federal poverty level, the Commission has made efforts to protect low-income households from electricity rate increases while also helping those households to reduce their energy usage and achieve greater bill savings without compromising their health or safety.

Low-income customers participating in the CARE program are already mostly protected from rate increases that may result from the Cap-and-Trade program.⁵⁵ However, there are reasons why it is sensible to consider providing additional assistance to low-income households beyond shielding them from rate increases. Under the Cap-and-Trade program, it is possible, and, in our view, likely, that low-income households' non-energy expenses will increase as businesses pass through the direct and indirect costs of compliance with Cap-and-Trade into the prices they charge for goods and services. The impact of these price increases will likely be proportionally greater on lower income households as these households tend to spend a greater proportion of their incomes on basic goods and services.

5.2.2.4. Maintain Competitive Neutrality Across Load-Serving Entities.

Consistent with existing Commission policy and the Cap-and-Trade regulation, it is appropriate to distribute allowance revenues in a way that does not place CCAs or other load-serving entities at a competitive disadvantage compared to the utilities that we directly regulate. The Cap-and-Trade regulation specifically requires that in deploying the auction revenues generated from the sale of allowances that the "[i]nvestor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators."⁵⁶ This policy objective is one that this Commission seeks to uphold regardless of how allowance revenue is apportioned, and we therefore consider the objective to be a high priority.

⁵⁵ Pursuant to § 739.1, CARE customers in Tier 3 may see a moderate increase in rates as a result of Cap-and-Trade.

⁵⁶ 17 CCR § 95892 (d)(4).

5.2.2.5. Customer Education

Consistent with SB 1018, we believe that any GHG allowance allocation methodology should be communicated clearly and effectively with all ratepayers. However, this objective does not provide significant guidance about how best to allocate GHG revenues, except to the extent that the adopted allocation methodology should be understandable to ratepayers. Because the objective of customer education does not assist us in developing an overarching allocation methodology, we designate this objective as a medium priority for the purposes of developing that methodology. However, consistent with SB 1018, we consider customer education as an important component of our GHG allowance revenue distribution methodology. In setting forth the parameters of any customer education program, however, we wish to maximize allowance revenue received by ratepayers. Therefore, we intend to adopt a targeted and efficient customer education and outreach program.

5.2.2.6. Achieve Administrative Simplicity and Understandability

While it is important to ensure that any proposal adopted in this proceeding is as simple and inexpensive to administer as possible, we do not believe that the simplest and least costly proposal to administer is in all cases the best plan. The medium priority that we place on this objective reflects the importance of choosing a realistic plan without compromising our other primary objectives: to reduce carbon emissions over time while also preserving, where appropriate, a carbon price signal in energy rates; to prevent economic and emissions leakage; and to reduce adverse impacts on low-income households. These primary objectives directly address the challenges posed to the Commission as a result of the Cap-and-Trade program, and it is therefore reasonable to prioritize them over a desire for administrative ease. However, we

acknowledge and factor into our decision the fact that our adopted methodology should not be so complex that it cannot be implemented in a timely manner and at reasonable cost.

5.2.2.7. Distribute Revenues Equitably Recognizing the “Public Asset” Nature of the Atmospheric Carbon Sink

No party to this proceeding ranked this objective as a high priority. While we agree that it does not rise to the level of importance of other high priority objectives, we do not believe it should be so easily disregarded and designate it as a medium priority objective. As discussed earlier, we are not persuaded that allocating revenues on the basis of who is polluting the most, and therefore will face relatively greater costs under the Cap-and-Trade regime, is, as a general matter, equitable or recognizes the public nature of the atmospheric sink. Such an approach would, in effect, serve to reward the very behavior the Cap-and-Trade program is seeking to mitigate. Returning revenues equally to all residential customers is more equitable and comports with the idea of common ownership of the atmosphere given that residential ratepayers will ultimately bear the increased costs as a result of the Cap-and-Trade program, as discussed in greater detail later in this decision.

5.2.2.8. Correct for Market Failures that Lead to Ongoing Underinvestment in Carbon Mitigation Activities and Technologies

While it is intuitively appealing to use GHG allowance revenues to invest in certain technologies or carbon mitigation activities, such as energy efficiency or clean energy, we do not feel that it is important to earmark allowance revenues solely as a means of correcting for any existing market failures. As noted by the Joint Utilities and TURN, we have many ongoing proceedings that specifically address carbon mitigation measures such as energy efficiency and

renewable energy, and these proceedings provide a more appropriate venue for consideration of proposals to specifically address market failures.

Overcoming market failures is a key objective of many of these proceedings; in fact, the creation of such standards as the deployment of all cost effective energy efficiency and a 33% Renewables Portfolio Standard are in place, in part, to overcome market failures and barriers to entry. Furthermore, we have deployed significant dollars toward such activities as research and development. These efforts include funding authorized pursuant to the California Solar Initiative, monies allocated to support emerging clean energy technologies via the Public Goods Charge as well as the newly created Electric Program Investment Charge and various approvals of utility requests for funding related to emerging clean energy technology development. All of these are part of our ongoing efforts to assist in overcoming market barriers to entry for new technologies. Finally, the presence of a carbon price signal itself will serve to correct for some market failures and assist in overcoming hurdles for new clean energy technologies by virtue of the internalization of the economic and environmental cost of emitting carbon. Therefore, we designate this objective to be low priority and do not intend to focus our efforts on adopting a GHG allowance revenue allocation methodology that will specifically address this objective.

5.3. Section 748.5

SB 1018, which adopts § 748.5, sets forth parameters that guide and limit the GHG allowance revenue allocation methodology that the Commission may approve. On July 11, 2012, the ALJs in this proceeding issued a ruling soliciting party feedback on the provisions of the code and its impact on parties' GHG

revenue allocation proposals. Parties' responses yielded significantly different opinions about the meaning of provisions in § 748.5.

The California Supreme Court has enunciated clear standards for courts or state agencies to use in construing a statute. The Commission must act as follows:

. . . look to the statute's words and give them their usual and ordinary meaning. The statute's plain meaning controls the court's interpretation unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy. . . .

Where more than one statutory construction is arguably possible, our policy has long been to favor the construction that leads to the more reasonable result. This policy derives largely from the presumption that the Legislature intends reasonable results consistent with the apparent purpose of the legislation.⁵⁷

Although the courts remain the ultimate arbiters of statutory meaning, courts accord deference to the Commission's reasonable interpretation of statutes.⁵⁸ We apply these rules of statutory construction below as we interpret and implement the provision of § 748.5.

As noted in the above quoted excerpt, we are also guided by legislative history, including, for example, Historical and Statutory Notes.⁵⁹ However, the

⁵⁷ *Imperial Merchant Services, Inc. v. Hunt* (2009) 47 Cal.4th 381, 387-388; see also, *e.g.*, *People v. Canty* (2004) 32 Cal.4th 1266, 1276 and *Lungren v. Deukmejian* (1988) 45 Cal.3d 727, 735.

⁵⁸ *Greyhound Lines, Inc. v. Public Utilities Commission* (1968) 68 Cal.2d 406, 410; *Lockyer v. City and County of San Francisco* (2004) 33 Cal.4th 1055, 1090-1091.

⁵⁹ To our knowledge, the Historical and Statutory Notes for SB 1018 are silent on § 748.5.

rules of statutory construction, as set forth above, direct us to look first to the language of the statute itself and we give those words their usual and ordinary meaning. “If there is no ambiguity in the language of the statute, ‘then the legislature is presumed to have meant what it said, and the plain meaning of the language governs.’”⁶⁰

In this manner, today’s decision applies the rules of statutory construction in implementing § 748.5.

5.3.1. Section 748.5(a)

Section 748.5(a), excerpted below, sets forth the extent of the Commission’s authority to allocate GHG allowance revenues to certain customer groups. In the following sections we address the authority granted under § 748.5(a) and construe the meaning of “small business” and “emissions-intensive and trade-exposed.”

Except as provided in subdivision (c), the commission shall require revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of greenhouse gas allowances to electric utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations to be credited directly to the residential, small business, and emissions-intensive trade-exposed retail customers of the electrical corporation.

5.3.1.1. Authority

Several parties, including DACC, CCC, DRA, the Large Users, the Joint Utilities, and PacifiCorp take a restrictive reading of § 748.5(a), interpreting this section as limiting the customer classes to whom we may directly credit GHG allowance revenues. The Joint Parties, however, argue that § 748.5(a) does not expressly limit the return of allowance revenues to other customer groups.

⁶⁰ *Smith v. Rae-Venter Law Group* (2002) 29 Cal.4th 345, 358.

Application of the first rule of statutory construction requires that we give the words of the statute their usual and customary meaning. A plain language reading of § 748.5(a) yields no ambiguity. Section 748.5(a), by designating specific customer classes (namely residential, small business, and emissions-intensive and trade-exposed) as the recipients of directly credited GHG allowance revenues prohibits us from granting direct relief to customer groups outside those classifications.

5.3.1.2. Small Business

Section 748.5(a) requires the direct return of GHG allowance revenues to small business customers, but does not define the term “small business.” There is no common usage demarcation point for classifying a business as small, and the term as used in the statute is ambiguous. A review of the statutory history yields no further information to relieve the ambiguity. Therefore, we rely upon previous Commission direction in adopting a definition of small business that we believe comports with the Legislature’s apparent intent, serves to promote, rather than defeat, the statute’s general purpose, and avoids a statutory construction that would lead to any absurd consequences.⁶¹

The July 11, 2012 Ruling soliciting party comments on the effects of SB 1018 specifically requested party comments on the meaning of the term “small business” under § 748.5(a). In that ruling, the assigned ALJs proposed several possible criteria that could be considered to interpret “small business,” including guidelines of the federal Small Business Administration (SBA) and the California Department of General Services (DGS). For most industries, the SBA defines a "small business" either in terms of the average number of employees

⁶¹ Day v. City of Fontana (2001) 25 Cal. 4th 268 at 272.

over the past 12 months or the average annual receipts over the past three years.⁶² The DGS considers a small business to be one that, among other criteria, has either 100 or fewer employees or average annual gross receipts of \$14 million or less over the last three tax years.⁶³ In addition, the July 11, 2012 Ruling noted that many utilities have specific commercial and industrial tariffs that are delineated based upon the customer's typical amount of electrical demand. Many parties responded providing a host of criteria for our consideration.

The Agricultural Parties argue that the term "small business" should be broadly defined and the classification should be based on more than just electric demand characteristics. For agricultural customers, the Agricultural Parties recommend that the Commission adopt the California DGS definition of small business, which they feel best reflects the scope of business customers' relevant business attributes. They argue that these characteristics should prevail over those set forth by SBA because the SBA definition does not account for differences between California's economy and the economy of the nation as a whole. Furthermore, these parties argue that the SBA definition, by excluding non-profits, results in the exclusion of schools and other entities, for which relief may be warranted. Finally, the Agricultural Parties argue that a definition based upon electricity usage is inapplicable because there is little correlation among agricultural entities between business size and electricity demand.

⁶² SBA defines a size standard – whether based on number of employees or annual receipts – for each private sector industry in the U.S. economy, using the NAICS to identify each industry. SBA publishes a Table of Small Business Size Standards, which is available at http://www.sba.gov/sites/default/files/files/Size_Standards_Table.xls.

⁶³ For DGS Small Business Eligibility Requirements see: <http://www.dgs.ca.gov/pd/Programs/OSDS/SBEligibilityBenefits.aspx>

DRA, on the other hand, recommends that the Commission designate as small businesses those customers with maximum electric demand below 20 kW, as established in the small business tariffs of SCE and SDG&E. To support its case, DRA cites to D.10-10-032, which defines a small business customer as a non-residential customer with annual electric usage of 40,000 kWh or less or an energy demand of 20 kW or less.⁶⁴ DRA argues that it is more practical and administratively simple for utilities to define small businesses by their electricity demand for the purpose of determining which businesses are eligible for bill relief. DRA states that the utilities should have knowledge about which customers have the capacity to draw more or less than 20 kW in demand. DRA suggests that other methods would require self-certification and utility verification and would be administratively burdensome and expensive.

Like DRA, the Joint Utilities prefer a usage-based approach; however, they suggest a 200 kW demand limit. Under the Joint Utilities' proposal, the method for distinguishing small and large businesses is that 'large' businesses would be any business that demands 200 kW or more for three months within any 12 month historical period. In the converse, any business that draws less than 200 kW for at least nine months within a 12 month historical period would be designated as a small business. The Joint Utilities, like the Agricultural Parties, prefer a broad definition of small business and argue that the 20 kW designation is too restrictive in that it only accounts for micro-businesses and would exclude

⁶⁴ D.10-10-032 also states that a small business customer is a customer who meets the definition of "micro-business" in California Government Code Section 14837. Section 14837 defines a micro-business as a business, together with its affiliates, that has average annual gross receipts of \$3,500,000 or less over the previous three years or, is a manufacturer, as defined in Section 14837 subdivision c), with 25 or fewer employees. D.10-10-032 at 6-7 and 14.

many vulnerable California business entities from receiving assistance. The Joint Utilities reject the exact definition in D.10-10-032 arguing that that proceeding focuses on assisting only businesses that are “barely able to make ends meet.”⁶⁵ In contrast, the utilities argue that the 200 kW designation casts a wide enough net to account for most small businesses, rather than capturing primarily struggling micro-businesses.

The Joint Utilities also reject a similarly narrow definition contained in § 331, which defines a small business as a ‘small commercial customer’ having demand of less than 20 kW. SCE and SDG&E in particular interpret the term ‘commercial’ in their tariffs to exclude agricultural customers, whereas the term ‘business’ is generally interpreted to encompass all non-residential customers. They argue that the Legislature’s use of the term “business” rather than “commercial” should be interpreted to mean any non-residential customer. Finally, the Joint Utilities argue that using any other agency definition, such as that of the SBA and DGS, is administratively burdensome and unmanageable because they would require the utilities to perform expensive information-gathering and ongoing verification activities.

PacifiCorp agrees with the Joint Utilities and DRA that the difficulty involved in administering any non-usage based definition would be prohibitive. PacifiCorp, like DRA, supports the definition for small business adopted in D.10-10-032. However, PacifiCorp argues that the most administratively simple method is to define small businesses by their participation in a specific rate schedule. MEA suggests that we should employ a long-established methodology

⁶⁵ R.10-05-006 at 7.

regarding small business customers, but does not cite to any specific decision or mandate.

In construing the meaning of the term “small business,” we acknowledge that any definition has trade-offs, and no one definition can adequately account for all the entities that could reasonably be considered to be a small business in California. As stated by the Joint Utilities, “bright-line, usage based thresholds to define ‘small business’ customer may mitigate the administrative impracticality of the definition but would still expose many customers to...rate increases. On the other hand, more nuanced definitions, such as those used by state and federal small business statutes and agencies, would require [utilities] to engage in time-consuming and costly information gathering and verification processes.”⁶⁶

Relying upon previous Commission precedent, we find that a usage-based definition for small businesses that relies upon electric demand is appropriate and promotes the apparent intent of the Legislature to return GHG revenues directly to small business customers. Therefore, we adopt a usage-based definition that designates a small business as one with an electric demand that does not exceed 20 kW in more than three months within the previous twelve month period. The Commission has historically relied upon a 20 kW demarcation point to define small businesses with varying qualifiers, depending on the program in question. Here, we find it appropriate to adopt the suggestion of the Joint Utilities to allow for some flexibility in demand by requiring that electric demand not exceed 20 kW in more than three months within the previous 12 months. It is reasonable to look at the previous 12-month period because doing so more accurately accounts for the average demand of the small

⁶⁶ Joint Utilities Comments on the Impact of SB 1018, August 1, 2012 at 2-3.

business, and it is appropriate to allow some flexibility in demand (i.e. the ability to exceed 20 kW in no more than three months in a 12 month period) because doing so avoids penalizing a business for demand that exceeds 20 kW once or twice in a year, which may represent anomalies in operations. Finally, we note that a 20 kW demarcation point is supported by all parties that propose a usage-based definition, with the exception of the Joint Utilities.

While the definition of “small” is open to some interpretation, we disagree with the Joint Utilities that the 200 kW level is appropriate. The Joint Utilities argue that a 20 kW demarcation is inappropriate because D.10-10-032, which uses such a demarcation, is intended to assist businesses experiencing economic trouble. The Joint Utilities therefore argue that the 20 kW threshold is not appropriate to identify all small business, but only those experiencing economic trouble.

We disagree. The fact that D.10-10-032 provides relief to businesses that are experiencing economic difficulty with less than 20 kW demand does not imply that, by adopting the same demarcation point here, we are somehow only helping businesses in distress. In fact, nothing could be further from the truth. The amount of electricity demanded is in no way related to the financial success of a business but reflects only the usage characteristics of the business.

We reject the SBA and DGS definitions for small business customers because we believe the administrative burden of adopting those definitions would result in some small businesses not receiving their portion of GHG revenues. Requiring a small business to essentially opt-in to receive GHG allowance revenue (because the utilities could not reasonably be expected to know the necessary information about their small business customers to determine whether they qualify for the SBA or DGS definitions) could result in a

large number of small businesses foregoing the process, either from lack of knowledge or due to the administrative burden. This result would undermine the plain language reading of § 748.5(a), which requires that GHG revenues be credited directly to small business customers. For this reason, we also do not adopt the opt-in process defined in D.10-10-032, which would allow a micro-business to opt into the relief provided in that decision if it can show that it meets the requirements of California Government Code Section 14837. Finally, because GHG allowance revenues reflect the cost of carbon in electricity rates, and the utilities will need to communicate with customers regarding eligibility as a small business, it makes sense from a structural standpoint to adopt a definition of “small business” that allows the utilities to interact with small business customers using existing rate structures and language.

Finally, we must define the range of customers with demand under 20 kW that will be classified as small businesses under § 748.5(a). The Joint Utilities argue that there should be a distinction between the term “business” and “commercial” as that term is used by the utilities in setting their commercial tariffs.

We agree. Providing GHG revenues solely to small business customers on commercial tariffs would result in many classes of non-residential customers that could reasonably be considered to be businesses, including agricultural and non-profit customers, receiving no GHG allowance revenue. In order to avoid an outcome where some small business customers receive GHG allowance revenues, while others do not, we find that any non-residential business customer that does not exceed 20 kW of demand in more than three months in the previous twelve months, as set forth above, should receive GHG allowance revenues. This interpretation comports most closely with the apparent intent of

the Legislature to provide GHG allowance revenue to small business customers of the utilities. Thus, any non-residential entity on General Service or Agricultural tariffs that meets the usage requirements set forth above shall receive GHG allowance revenues according to the methodology we adopt below for small businesses. This may include non-profit entities and others that are not covered in the SBA or DGS small business definitions.

5.3.1.3. Emissions-Intensive and Trade-Exposed

Section 748.5(a) requires the direct return of GHG allowance revenues to EITE customers, but does not provide a specific definition for the term “emissions-intensive and trade-exposed.” It is unclear from a plain language reading of the statute at what point an entity becomes emissions-intensive and trade-exposed, and a review of the statutory history yields no further information to relieve the ambiguity. The term “emissions-intensive and trade-exposed” does not appear elsewhere in statute, but it has been applied in common usage by ARB⁶⁷ to describe those entities designated in the Cap-and-Trade regulation that qualify for Industry Assistance.⁶⁸ No party to this

⁶⁷ ARB has used the terms “emission intensive” and “energy intensive” interchangeably.

⁶⁸ ARB, California’s Cap-and-Trade Program Final Statement of Reasons, December 2011 at 276 states: “We analyzed the potential for emission leakage by looking at emission intensity and trade exposure. ‘Emissions intensity’ is a measure of the impact that carbon pricing will have relative to a sector’s economic output. Those with higher emissions per unit of output were considered to be more emissions intensive. ‘Trade exposure’ is a measure of a sector’s ability to pass through a cost. Without assistance, industries that are both highly emissions-intensive and trade-exposed have the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements. To minimize the potential for leakage, the [Cap-and-Trade] program relies heavily on free allocation in the program’s early years. We believe that free allocation to industrial entities at risk of emissions leakage will help maintain the competitiveness of California industries. For

proceeding disputes that entities that qualify for Industry Assistance should receive GHG allowance revenue to mitigate GHG costs associated with their indirect emissions from purchased electricity. The rationale is that absent some form of offsetting compensation to address increased production costs resulting from the Cap-and-Trade program, the emissions associated with any given industrial activity will simply shift out of state, as demand for an industry's products shift to suppliers that are not subject to carbon regulation, and/or that industry simply relocates their operations to localities outside of the Cap-and-Trade program. This risk of emissions leakage results not only from the direct compliance obligations entities may face under the Cap-and-Trade program but also indirect costs embedded in the price of electricity they use, to the degree retail rates reflect carbon prices. The allocation of GHG revenues to EITE entities, as required by § 748.5 will address leakage risk as a result of indirect emissions.

Some parties, however, argue that ARB's evaluation of entities that pose a leakage risk is too narrow and should also include entities that have substantial indirect GHG cost exposure due to their consumption of electricity. In their original proposal, the Agricultural Parties argue that farmers and food processors face increases in electricity rates due to the implementation of the Cap-and-Trade program, and further assert that these cost increases cannot be passed on to consumers because most farmers and food processors compete in a global commodity market and cannot control the pricing of their goods. As such, the agricultural industry could become a source of leakage if production shifts

as long as ARB assesses that risk of leakage persists, allowances will be allocated for free to those at risk..."

out-of-state or abroad, which could result in increased demand for electricity in more carbon-intensive markets. The agricultural sector as a whole was not expressly included under the cap, though should an agricultural entity operate a covered facility that emits more than 25,000 MTCO₂e, that entity would be a Covered Entity under the Cap-and-Trade regulations and would be required to retire allowances.

Similarly, the Large Users argue that the definition of “emissions intensive” should not apply only to direct emissions, as is the case for those entities qualifying for Industry Assistance. Rather, the definition should include entities that are indirectly emissions-intensive due to the significant use of electricity in their production processes. Regarding the definition of “trade-exposed,” the Large Users suggest that the Commission establish a procedure by which it can determine which customers pose a leakage risk and are therefore trade exposed under § 748.5. The Large Users also argue that the Commission should establish a “safe harbor,” which would provide that any entity that sells a significant portion of its output to Industrial Covered Entities would automatically be covered as trade-exposed. In contrast to the Large Users’ comments, PacifiCorp offers that an electric intensive industry may actually not have high emissions; therefore, the Commission must clearly set guidelines for the designation of EITE.

The Joint Utilities argue that most, if not all, non-residential, private-sector electric customers are competing with entities that reside outside of California and therefore are “emissions-intensive and trade-exposed.” Therefore, the Joint Utilities recommend a broad definition of EITE to include such sectors as agriculture and manufacturing as well as retail, services, and gas/oil/mining sectors that are subject to competition from surrounding states, nationally, or

globally. CCC argues the retail EITE customers of CHP facilities should receive GHG allowance revenues on the same basis that regular EITE utility customers receive an allocation.

At a minimum, because ARB uses the criteria “emissions-intensive and trade-exposed” to evaluate entities qualifying for Industry Assistance, it is reasonable to interpret § 748.5(a) to mean that GHG allowance revenues must be allocated toward those entities that qualify for Industry Assistance under the Cap-and-Trade regulation. The presence of a carbon price signal in electricity rates will result in even higher emissions cost exposure for these entities and therefore higher costs under the Cap-and-Trade program, thus further aggravating leakage risk. In making this finding, we agree with CCC that entities that qualify for Industry Assistance should receive a GHG revenue allocation, as described further herein, regardless of whether the entity purchases or consumes electricity from its own CHP facility, a third-party owned CHP facility, or from an investor-owned utility.

In addition to the provision of allowances to those entities that qualify for Industry Assistance, the use of the general terms “emissions-intensive and trade-exposed,” rather than the more formal terminology adopted in the Cap-and-Trade program can be construed to mean that § 748.5(a) is intended to offer broader protection than solely to those entities qualifying for Industry Assistance. In making this finding, however, it is important to note that § 748.5(a) specifically ties together the terms “emissions-intensive” and “trade-exposed” by the word “and.” This indicates that, in order to be eligible to receive GHG allowance revenue under the statute, entities must be both emissions-intensive and trade-exposed; designation as solely “emissions-

intensive” or “trade-exposed” does not result in an entity being classified as EITE.

Applying a more general reading of “emissions-intensive and trade-exposed” under § 748.5(a), we find that the EITE designation for the purposes of indirect emissions should extend to customers in industries identified by ARB as qualifying for Industry Assistance, but with emissions levels less than 25,000 MTCO₂e. Such entities, although they do not have a direct compliance obligation under the Cap-and-Trade regime, presumably also face similar leakage risk as their larger covered peers within a given industrial sector as a result of their indirect emissions, which could put them at a competitive disadvantage with entities outside of California. An allocation of GHG revenues to avoid leakage for these entities comports with the apparent intent of the Legislature to provide assistance to EITE entities. However, as described in more detail in the section adopting our GHG allowance revenue allocation methodology for EITE customers, as defined herein, ARB must have certain types of information, for example, production data, associated with an entity in order to determine the appropriate amount of GHG allowances to distribute to that EITE entity. To the degree the approach taken to address indirect emissions costs will mirror that used by ARB for direct emissions costs, similar data will be required to provide compensation to address these indirect costs. Therefore, EITE customers that have emissions levels less than 25,000 MTCO₂e and that operate in sectors that qualify for Industry Assistance must voluntarily opt into the Cap-and-Trade program in order to be eligible to receive allowance revenue for the indirect emission costs associated with their electricity purchases, unless

another suitable method can be developed to accurately obtain the necessary information to calculate revenue returns for these customers.⁶⁹

We disagree with the Joint Utilities that the presence of competition between business entities within California and outside of California results in an entity being trade-exposed and therefore eligible to receive GHG allowance under § 748.5(a). Using that logic, ARB would have provided industry assistance to all businesses within California that have any direct emissions and face competition outside of California, a clear watering-down of the intention of designating certain eligible industries as qualifying for Industry Assistance. Furthermore, the mere presence of indirect emissions attributable to a business entity from its electric purchases does not necessarily result in that entity being considered emissions-intensive. The provision of allowances to all businesses that face competition outside of the state would be an extremely broad construction of § 748.5(a).

However, examination of the divergent stances taken by ARB and the Joint Utilities on the definition of EITE points to the fact that a gray area exists in which some entities may pose a leakage risk as a result of their indirect emissions but not be an Industrial Covered Entity or in an industry that qualifies for Industry Assistance. The Large Users make a compelling case that electricity intensity could be correlated with emissions intensity (although not always, as noted by PacifiCorp) and leakage risk due to trade exposure could become an

⁶⁹ The Commission may consider alternative methods of obtaining necessary information that would not require such entities to opt into the Cap-and-Trade program in the phase of this proceeding addressing implementation, as set forth in Section 6. The exact method of revenue return to these entities will be finalized in the implementation phase of this proceeding.

issue for some entities due to the embedded cost of carbon in electricity prices. The Agricultural Parties also make a strong argument that they are leakage prone due to being subject to global commodity prices and often being electricity intensive, depending on an entity's need to pump water. However, the Agricultural Parties have not provided any data to show that this is indeed the case, and it is not clear that the agricultural parties would be considered emissions-intensive and trade-exposed, as required to be eligible to receive allowances under § 748.5(a).

Given these concerns, and the lack of specific information in the record to identify and classify entities that do not qualify for Industry Assistance under the ARB regulations but may be emissions-intensive and subject to leakage due to increased costs from their indirect electricity emissions, we are convinced that an additional process is warranted in order to ensure that all EITE customers under § 748.5(a) receive GHG allowances. This process should explore the possibility that certain sectors may become emissions-intensive and trade-exposed as a result of their GHG costs from electricity purchases. The principle question requiring further study appears to be: which industries, outside of those already designated by ARB to be eligible for Industrial Assistance, pose a leakage risk as a result of their indirect emissions costs resulting from their electricity purchases. We will address this issue in this or a subsequent proceeding, and we will consider, among other options, a robust public participation process similar to that used by ARB (and held in coordination with ARB) to classify certain entities as qualifying for Industry Assistance. Promptly after issuance of this decision,

we anticipate the assigned Commissioner or assigned ALJs shall set forth the process by which the Commission will undertake an evaluation of this issue.⁷⁰

Finally, there may be instances where an entity that is classified as EITE may also qualify as a small business. It is our intention to avoid duplicative distributions of GHG allowance revenue to any single entity; however, we lack adequate record on which to adopt a solution to address this possibility. We assume it will be easier from an administrative standpoint for a utility to identify an EITE customer and remove said customer from a list of customers authorized to receive EITE revenues, if it also receives revenues as a small business, than it will be to execute the opposite. However, we require the utilities to set forth a methodology for addressing this possible situation in Section 6, below. Our preference would be for the approach taken to be uniform across the investor-owned utilities, and we encourage them to work together in developing their proposed approach.

In summary, for the purposes of today's decision, we interpret § 748.5(a) to mean that any entity in an industry that qualifies for Industry Assistance under ARB's Cap-and-Trade regulation, regardless of the amount of emissions produced, shall receive GHG allowance revenue. Those entities with emissions less than 25,000 MTCO₂e must opt into the Cap-and-Trade program in order to be eligible to receive allowance revenue related to their electricity purchases, unless another suitable method can be developed to accurately obtain the necessary information to calculate revenue returns for these customers. Should ARB expand the list of industry sectors that are eligible for Industry Assistance,

⁷⁰ The assigned Commissioner or assigned ALJs may modify the date of issuance of further guidance. Guidance may come in the form of a ruling, amended scoping memo, or any other means deemed appropriate.

those newly added sectors should also receive allowance revenue calculated using the methodologies we adopt in this decision to address their purchased electricity costs. Further, should ARB shrink the list of sectors eligible for Industry Assistance, those sectors will no longer be eligible for compensation on a going forward basis.

5.3.2. § 748.5(b): Education Requirements

Section 748.5(b), excerpted below, mandates that the utilities adopt and implement, not later than January 1, 2013, a customer outreach plan for purposes of obtaining the “maximum feasible public awareness” of the crediting of GHG allowance revenues. Costs associated with the implementation of this plan are subject to recovery in rates pursuant to § 454. In the July 11, 2012 Ruling, the assigned ALJs requested feedback from parties on several elements of this provision including how to interpret “maximum feasible public awareness,” and whether customer outreach costs should be funded by a source other than GHG allowance revenues. Several parties provided feedback on these issues. In the following sections we interpret the meaning of “maximum feasible public awareness” and address issues pertaining to cost recovery of customer outreach and education.

Not later than January 1, 2013, the commission shall require the adoption and implementation of a customer outreach plan for each electrical corporation, including, but not limited to, such measures as notices in bills and through media outlets, for purposes of obtaining the maximum feasible public awareness of the crediting of greenhouse gas allowance revenues. Costs associated with the implementation of this plan are subject to recovery in rates pursuant to Section 454.

5.3.2.1. Maximum Feasible Public Awareness

A reasonable reading of the plain language of § 748.5(b) yields that the utilities must adopt and implement a customer outreach and education program

that maximizes public awareness of the crediting of GHG allowance revenues. However this outcome is tempered by the term “feasible.” Given that SB 1018 was passed in late June of 2012, it will not be feasible for the utilities to adopt and implement a comprehensive program by January 1, 2013. Customer outreach and education, however, can be expanded in 2014 and beyond.

The statute does not set forth any metrics for measuring the standard of “maximum feasible public awareness,” and a reading of the legislative history does not provide any further guidance. The July 11, 2012 Ruling asked parties to provide suggestions on goals that could be adopted to measure achievement of the standard. The Joint Utilities suggest that “maximum feasible public awareness” is a flexible standard, and that the Commission should interpret it in the same way it generally interprets the “reasonableness” of utility expenditures to meet a specific goal, e.g., by comparing the benefits of the goal with the expenditures needed to achieve that goal. Furthermore, the Joint Utilities suggest that outreach should be modest and realistic using low cost, existing outreach options, such as bill communications, website information, and the use of customer call centers. In contrast, the Joint Parties argue that in order to achieve maximum feasible public awareness, revenues must be returned in a way that is visible, understandable and leverages new and existing customer clean energy programs. Otherwise, the Joint Parties assert that the Commission will have limited means of gauging customer awareness.

The specifics of our adopted customer education program are discussed in more detail below; however, we agree with the Joint Utilities that “maximum feasible public awareness” is a flexible standard that hinges on the term “feasible.” We generally agree that using our long-held reasonableness approach to evaluate costs as compared to achievement of goals will comport with the

provisions § 748.5(b). We fully recognize that evaluating the ability of any particular program's achievement of public awareness will be difficult, somewhat subjective, and likely an iterative process. We do not agree with the Joint Parties that adopting clean energy or energy efficiency programs will increase our ability to measure or result in maximization of public awareness as required under § 748.5(b).⁷¹

We are persuaded that the education program under § 748.5(b) must be modest in 2013. Therefore, we will focus our efforts on setting parameters for an interim program in 2013 and adopting a process to develop a more robust program in the future. We also agree with the Joint Utilities that any customer education program should be low-cost. We strongly support the objectives of customer outreach and education, while at the same time focusing our efforts first and foremost on maximizing the amount, and therefore benefit, of GHG allowance revenue returned to customers.

5.3.2.2. Cost Recovery

Section 748.5(b) states that costs associated with the implementation of customer outreach programs "are subject to recovery in rates pursuant to § 454." This language makes it clear that the utilities may recover the cost of customer outreach programs in rates, subject to the procedural requirements set forth in § 454, but it does not directly address whether GHG allowance revenues can be used to pay customer outreach costs.

⁷¹ Such programs could occur entirely out of the public view, as do many clean energy deployment programs, or could apply only to a specific customer class. The only awareness measurement we could undertake in the second circumstance is to measure the number of customers that take advantage of a particular program. This does not, however, provide us with any information regarding general public awareness of GHG allowance revenue crediting.

The Joint Utilities argue that the costs of customer outreach should be funded directly by GHG allowance revenues through each utility's ERRRA account. DRA fundamentally agrees with the Joint Utilities that it would be best for customer outreach costs to be funded by GHG allowance revenues. However, DRA is unsure if this approach complies with the requirements of § 748.5(a), which mandate that all revenues (except those used to fund energy efficiency projects) be "credited directly" to residential, small business, and EITE customers.

DACC argues that customer education costs should be borne only by those who receive the education, and assert that education should be solely directed to (and therefore funded by) residential customers. Therefore, DACC argues, only the residential sector's proportional share of revenues should be used to fund educational programs. DACC states that under no circumstances should customer education efforts be funded by ratepayers generally.

Working from the assumption that the utilities may recover customer outreach costs in rates, we have two possible ways to accomplish that recovery. One way, which might alleviate the uncertainty expressed by DRA, would be to have all of the GHG revenues flow back to residential, small business and EITE ratepayers, add the outreach costs to rates, and have those ratepayers that receive revenues pay the outreach costs back to the utilities.⁷² This approach, however, is unnecessarily convoluted, and is not supported by any party.

⁷² Nothing in § 454 precludes the Commission from considering issues of equity or undertaking a cost/benefit analysis in allocating revenue requirements differently to different ratepayer classes or groups. In this case, it is appropriate to allocate customer outreach costs to those customers who will be the beneficiaries of the direct crediting of GHG allowance revenue.

The other approach would be to use the GHG allowance revenues to fund customer outreach. This approach is supported by the majority of parties. As a practical matter, the results from this approach are the same as the prior approach – the utilities are made whole for their costs, and the appropriate ratepayers bear those costs. This is consistent with Section 748.5(b), which allows the utilities to recover outreach costs from ratepayers. It would be absurd to require the ratepayers to first receive the same amounts of money that they will then pay back to the utility, when the same result can be accomplished in a manner consistent with the law. We decline to elevate form over substance for no reason. Accordingly, we adopt the approach recommended by the Joint Utilities, DRA, and DACC, under which the implementation costs associated with the customer outreach program under § 748.5(b) are reasonably paid for out of general GHG allowance revenues.

We agree with DACC in principle that those who are the targeted recipients of the customer education program should bear the costs, but, while we envision the majority of customer education will focus on the residential sector, § 748.5(b) clearly states that the outreach program should achieve maximum public awareness. Public awareness does not seem to stop with residential customers. Therefore, customer education program costs shall be funded by a portion of all GHG allowance revenues, not those solely designated for residential customers.

5.3.3. § 748.5(c): Funding of Energy Efficiency or Clean Energy

Section 748.5(c), excerpted below, provides that the Commission may allocate up to 15% of the GHG allowance revenues for clean energy and energy efficiency projects. Under the provisions of § 748.5(c), only programs established pursuant to statute that are administered by the utilities and that are not

otherwise funded by another funding source may receive funding from allowance revenues. The July 11, 2012 ALJ ruling requested that parties provide comment on several aspects of this subsection, including how to interpret the meaning of “established pursuant to statute” and “not otherwise funded by another funding source.” In addition, several parties opined on how § 748.5(c) affects the Commission’s ability to determine the percentage of GHG allowance revenues dedicated to energy efficiency and clean energy projects. We address each of these issues in the following sections.

The commission may allocate up to 15 percent of the revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of greenhouse gas allowances to electrical distribution utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations, for clean energy and energy efficiency projects established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source.

5.3.3.1. Authority Granted

Parties express, directly or indirectly, a variety of views on the Commission’s ability to set the percentage of GHG allowance revenues directed toward energy efficiency or clean energy projects under § 748.5(c). PacifiCorp, MEA, SEIA, CCSF, IEP and the Joint Utilities appear to interpret § 748.5(c) as permitting the Commission to determine the portion of GHG allowance revenue to direct toward energy efficiency and clean energy programs, up to a cap of 15%. The Joint Parties, in contrast, state that the adoption of § 748.5 reflects the Legislature’s support for using utility allowance revenues for investment activities. On this basis, the Joint Parties suggest that it would be appropriate for the Commission set aside the full 15% of revenues. The Efficiency Council

appears to argue that § 748.5(c) requires that we allocate the full 15% of revenues for energy efficiency and clean energy.

A reading of the plain language of this subsection is permissive, consistent with the interpretation suggested by the Joint Utilities and other parties. The statutory language states that the Commission “...*may* allocate *up to* 15% of the revenues” (emphasis added). The inclusion of the words “may” and “up to” imposes a cap, not a minimum or a specific requirement, on the amount of allowance revenues directed towards energy efficiency and clean energy projects. The clear absence of any lower bound plainly indicates that the Commission, if it deems it the best outcome, may forego allocating GHG allowance revenues towards energy efficiency or clean energy programs while remaining in compliance with § 748.5(c).

5.3.3.2. Established Pursuant to Statute

The Joint Utilities state that they are unaware of any utility-run clean energy or energy efficiency program that is established pursuant to statute. This comment suggests that the Joint Utilities take a restrictive interpretation of the statute; the law must establish a particular energy efficiency or clean energy project in order to receive GHG allowance revenues. DRA, in stating that its original proposal for the creation of a Consolidated Financing Program does not meet the requirements of § 748.5(c), takes a similarly restrictive reading of this language. Like the Joint Utilities, DRA is unclear what programs would meet the requirements of subdivision (c) and requests that the Commission develop such criteria in this decision.

The Joint Parties argue that an overly restrictive reading of the provision would render subdivision (c) effectively meaningless and suggest that such a reading is inconsistent with longstanding canons of statutory interpretation as

well as the asserted interest of the Legislature in exploring investment opportunities. The Joint Parties argue that a more reasonable interpretation of this language is that the Commission must stay within its jurisdictional purview by allocating revenues to buttress clean energy and energy efficiency projects that are authorized under the Commission's existing statutory authority. SEIA argues that its proposal to allocate a portion of revenues toward upgrades to the distribution system that are required as a result of the interconnection of renewable generation projects is allowable under subdivision (c). By making this argument, SEIA appears to take a similar stance to the Joint Parties; projects authorized by the Commission consistent with our statutory authority meet the requirements of this subsection. Finally, GPI and IEP suggest that funds be allocated to a particular biomass program that was the subject of an assembly bill under consideration.

Evaluating the words of the statute by their usual and customary meaning yields an ambiguity, as characterized by parties, that is not resolved through an examination of the legislative history. Therefore, we rely upon the jurisdiction of the Commission to establish energy efficiency and clean energy programs that are administered by the utilities (and allocate ratepayer funding toward those programs) pursuant to broad parameters set in statute. We find that, as argued by the Joint Parties, a restrictive read of § 748.5(c) would render the provision effectively meaningless, a perverse outcome that would require the Legislature to step into the role of adopting clean energy and energy efficiency programs and projects that have traditionally been under the Commission's statutory jurisdiction. Nothing in the plain language of the statute leads us to believe the statutory authority of the Commission has been altered. In addition, the presence of the word "project" rather than "program" implies that a project that

falls under the purview of a statutorily created program over which the Commission has jurisdiction, such as energy efficiency or renewable energy programs, would be considered to be “established pursuant to statute.”

5.3.3.3. Not Otherwise Funded

The Joint Utilities state that they are unaware of any utility-run project that is established pursuant to statute and not otherwise funded, implying a restrictive reading of the term “not otherwise funded.” PacifiCorp states that subdivision (c) is unclear because, presumably, many projects established pursuant to statute would already have some funding source identified. For example, all existing energy efficiency projects approved pursuant to the broad authority of the Commission to approve such projects are generally funded by ratepayers. Therefore, PacifiCorp argues that the Commission should interpret “not otherwise funded” to mean that the Commission may allocate GHG allowance revenue toward projects that would ordinarily be paid for directly by utility customers. The Joint Parties suggest that the intent of the Legislature was to avoid duplication and fund-shifting; therefore, a reasonable interpretation of this language is that revenues in this proceeding can be used to fund new and supplemental projects that build on and address gaps in the Commission’s current suite of customer programs.

While the ordinary meaning of the words of the statute clearly convey that a project must not otherwise be funded in order to receive funding through GHG allowance revenue, it is unclear, as articulated by parties, whether the statute prohibits the Commission from allocating GHG revenues toward existing projects. The legislative history offers no insight to clear the ambiguity. As suggested by the Joint Parties, we find that the most reasonable interpretation of the statute that promotes the statute’s general purpose is the requirement that

any GHG allowance revenue directed toward clean energy project be additional to previously existing activities, regardless of whether a project is new or already in existence. Shifting the funding for a program that was previously paid for by utility ratepayers to GHG allowance revenues would save money on energy efficiency or clean energy projects, but in general such a shift would not increase the availability of such projects and would violate the statute. While we envision that the majority of projects that could receive funding from GHG allowance revenues would be new or supplemental, it may be possible to fund an existing project with GHG allowance revenues so long as the general funding previously supporting that project is directed to another project within the same program (i.e. energy efficiency, Renewable Portfolio Standard, etc.).

5.4. GHG Allowance Revenue Distribution Methodology for PG&E, SCE and SDG&E

Below, we set forth our adopted methodology for allocating GHG revenues to the customers of the three large investor-owned utilities, PG&E, SCE, and SDG&E, inclusive of their CCA and DA customers. As discussed in later sections, we adopt a similar allocation methodology for the small and multi-jurisdictional utilities, with the exception of Bear Valley. In Section 6, we set forth a process to finalize all necessary details in order to fully implement the GHG revenue distribution methodology adopted in this decision.

5.4.1. Step 1: Return Revenues to Emissions-Intensive and Trade-Exposed Entities

After setting aside an appropriate portion of the GHG allowance revenues to be used for customer education and outreach and to cover administrative expenses (as described in detail later in this decision), PG&E, SCE, and SDG&E must first return GHG allowance revenues, including accrued interest, to those customers designated as EITE in Section 5.3.1.3 above. Parties offered a wide

variety of GHG allowance revenue return methodologies for our consideration, including returning revenues to EITE customers in direct proportion to their GHG electricity costs (volumetric return), allocating the allowances associated with the electricity usage of EITE customers back to ARB for distribution, allocating allowance revenues based upon various formulas that mirror ARB's allowance allocation methodology to Industrial Covered Entities qualifying for Industry Assistance, or applying other factors such as historical consumption to determine an appropriate allocation.

As described earlier in this decision, ARB, in designating certain industries as qualifying for Industry Assistance, did not opt to provide relief to those entities for the increased costs of purchased electricity due to the Cap-and-Trade program. In this decision we adopt a definition of EITE that, at this time, includes only those industries designated as qualifying for Industry Assistance, including entities within those industries that have emissions below the 25,000 MTCO₂e threshold. In adopting its Industry Assistance methodology, ARB engaged in a comprehensive public process resulting in a leakage risk classification for each covered sector (high, medium and low) as well as a variety of methodologies to calculate the number of allowances each entity would be freely allocated to address their compliance obligations under the Cap-and-Trade program. The adoption of these classifications and methodologies results in the provision of assistance to reduce the risk of leakage and to provide transition assistance while sending appropriate signals to engage in carbon mitigating activities.

We find it prudent to adopt a GHG allowance revenue distribution methodology that closely mirrors, to the extent practical, the allowance allocation process adopted by ARB for Industrial Covered Entities that qualify for Industry

Assistance because, as discussed earlier in this decision, the increased price of electricity inclusive of GHG costs will contribute to the leakage risk faced by those entities if not partially offset by freely allocated allowances or allowance revenue. Therefore, our intent is that EITE entities receive GHG allowance revenue associated with their electricity purchases in a manner parallel to the way in which they receive allowances for their direct emissions under ARB's Industry Assistance program. Adoption of this approach ensures that sectors with higher leakage risk receive proportionally greater transition assistance for increased electricity costs while also ensuring that the carbon price signal of electricity is not muted for any individual entity. Furthermore, this approach ensures that Industrial Covered Entities eligible for Industry Assistance receive GHG allowance revenues for indirect emissions based upon benchmarks and calculations for each industry in a manner that supplements ARB's approach to distributing allowances for direct emissions.

Our adopted approach comports largely with that suggested by the Large Users in their Option C; however, we do not adopt the exact formulas for calculating GHG revenue return to EITE customers proposed by the Large Users because the formulas are not sufficiently developed. Further record is needed before EITE allocation formulas can be finalized. Thus, we propose, but do not adopt, preliminarily EITE distribution formulas developed by Commission staff in Appendix A and set forth a process for finalizing these formulas, following a public vetting process, in Section 6 discussing implementation. Finally, we recognize that, should the Commission expand the definition of EITE entities to include sectors or industries that are not covered under ARB's Industry Assistance methodology, allocation formulas will need to be developed to return GHG allowance revenues to these entities for their indirect emissions. To the

extent practical, we envision the allocation formulas will rely on methodologies that are similar to those ultimately adopted to return GHG revenues to EITE entities that qualify for Industry Assistance under ARB's regulation. However, we recognize that there may be practical constraints in terms of the availability and administrative ease of collecting information that would be necessary to mirror ARB's approach. Therefore, we will consider other approaches if adhering to the model provided by ARB's compensation scheme proves impractical.

As noted above, for those entities that do not belong to sectors that are designated as eligible for Industry Assistance by ARB, our intent is to develop and adopt formulas that mirror the allowance allocation process developed by ARB. We take this view in lieu of alternative approaches suggested by parties for a number of reasons. First, as discussed earlier in this decision, barring certain extenuating circumstances, we are not favorably disposed toward proposals that return revenues to any class of ratepayers on a purely volumetric basis, as proposed by the Joint Utilities and others, because doing so would mute the carbon price signal and would therefore negate the incentive this signal would create for EITE entities to engage in energy conservation measures such as energy efficiency. We reject the proposal of the Joint Parties, which suggests that revenues be returned to EITE customers based upon historical electricity consumption, leakage risk and the incremental rate impacts forecast by the utilities on the customer class to which each EITE customer belongs. We believe that the methodology we adopt here achieves the goals of the Joint Parties to preserve a carbon price signal but does so using formulas that mirror the existing ARB process, which has been thoroughly developed and publicly vetted. Finally, although intuitively appealing, we reject as infeasible the Large Users'

Option A, which would have us give allowances in proportion to the GHG emissions associated with EITE customers' electricity use back to ARB for distribution because such a process would require a change in the Cap-and-Trade regulation adopted by ARB.

ARB's Cap-and-Trade regulation provides several different ways to calculate the allocation a given covered entity is eligible to receive. For some entities, ARB has developed a Product-Based Allocation methodology under which the number of allowances entities are eligible to receive is a function of their output and a sector specific emissions-per-unit output benchmark. For other entities, ARB has adopted an Energy-Based Allocation, under which the allocation an entity is eligible to receive is based on steam and fuel use benchmarks and the covered entity's historic steam and fuel use. Furthermore, ARB applies leakage risk factors to each sector. High-risk sectors will receive assistance at the same level throughout the duration of the Cap-and-Trade program, while medium- and low-leakage risk sectors will see their free allowance allocation decrease over time.

The adoption of methodologies that mirrors the ARB allowance allocation process to Industrial Covered Entities qualifying for Industry Assistance enables us to compensate EITE ratepayers while maintaining the carbon price signal in their rates, therefore providing much needed transition assistance while sending a signal to EITE customers to conserve or otherwise reduce the emissions from electricity consumption. This occurs because the ARB allowance allocation methodologies, which we mirror here, do not return allowances as a function of current emissions or electricity consumption, thus preserving the opportunity cost associated with emitting under the Cap-and-Trade regime. Finally, we note that we adopt this parallel methodology to ensure that EITE customers are

treated similarly for both their direct and indirect emissions. We believe this will help streamline future transitions should ARB modify the Cap-and-Trade regulation to include indirect emissions associated with electricity purchases by EITE entities in their formulas for allowance distribution to Industrial Covered Entities.

5.4.1.1. Third-Party CHP

As described earlier in this decision, Tesoro filed comments regarding specific concerns related to its Golden Eagle Refinery. Specifically, Tesoro argues that the Commission should address the lack of Industry Assistance that the Golden Eagle Refinery will receive from ARB for the purchase of electricity from a third-party-owned CHP unit. Tesoro points out that if the Golden Eagle refinery owned the same CHP unit, the GHG costs of its electricity production would be eligible for Industry Assistance. Tesoro argues that this mere difference in ownership status should not result in substantially different level of Industry Assistance. In order to provide assistance commensurate with a facility with on-site CHP, Tesoro suggests that the utilities be directed to set aside some of the allowance revenues they receive to cover the costs faced by refineries purchasing electricity from third-party CHP providers.

We agree that, based on the facts as Tesoro presents them, the lack of Industry Assistance for GHG costs associated with electricity purchased from third-party CHP units appears to result in disparate levels of assistance across refineries even when those refineries are substantially similar in their operations. A refinery that owns its CHP facility is eligible to receive assistance that more closely reflects its emissions costs exposure than a refinery that does not.

Therefore, we agree that it is appropriate to address the GHG costs of electricity purchased by refineries from third-party CHP through the use of the

allowance revenues the utilities will receive in a manner consistent with the intent of Tesoro's request. We set forth, but do not adopt, a preliminary methodology for distribution of allowance revenue to refineries that contract with third-party owned CHP in Appendix A. This methodology will be finalized through the implementation process set forth in Section 6, below. The issue of disparate treatment extends beyond the refinery sector, and it is important to ensure that all EITE entities that purchase electricity from third-party owned CHP receive equal treatment under the EITE GHG revenue allocation formulas ultimately adopted in this proceeding. Our intent in developing compensation formulas for EITE entities in this proceeding is to compensate them for the indirect emissions costs that are currently not addressed by ARB's approach to providing Industry Assistance. These indirect emissions costs are the Cap-and-Trade program costs that will be embedded in the price of electricity these entities purchase, whether they are purchasing that electricity from the investor-owned utilities, a DA provider, or a third-party owned CHP facility.

**5.4.1.1.1. Timing and Mechanics of GHG
Allowance Revenue Distribution to EITE
Customers**

We lack record at this juncture to determine the exact timing of the distribution of GHG allowance revenue to EITE customers, and the timing will ultimately depend upon the final formulas adopted. However, our initial thinking is that, as a result of the need to provide allocations on a revenue, rather than an allowance, basis, it may be preferable to provide compensation after a given Cap-and-Trade budget year has passed rather than beforehand. In order to better align the amount of compensation provided with actual revenues generated from the sale of emissions allowances, providing compensation after a given Cap-and-Trade program budget year has passed is preferable inasmuch as

it allows us to rely on actual market prices rather than projections, which, given the nascent state of the allowance market, are likely to be subject to a great deal of uncertainty. The exact timing of the revenue distribution to EITE customers each year will be finalized through the implementation process discussed in Section 6, below.

In order to help facilitate transparency and understanding of our GHG allowance revenue allocation methodology, an important principle proposed by several parties, GHG allowance revenues must be returned to EITE customers either via an on-bill credit against their electricity purchases or via a separate check, to be determined during the implementation process set forth in Section 6.⁷³ An on-bill return, if adopted, must be designated as such via a separate line-item, and a bill credit must be applied to the delivery component of the charges to ensure that all customers within a utility's service territory, irrespective of whether they are a bundled, DA, or CCA customer, are treated equally.

5.4.2. Step 2: Return Revenues to Small Businesses Customers

As described previously, § 748.5(a) directs the Commission to return allowance revenue to small businesses, which, for this purpose, we define as non-residential entities on General Service or Agricultural tariffs whose electric demand does not exceed 20 kW in more than three months within the previous twelve-month period. In their August 1, 2012, comments, the Joint Parties argue that, for the majority of small businesses in California, energy related costs

⁷³ Administrative costs associated with EITE revenue returns may be small in comparison to the size of the return. Furthermore, annual returns may exceed EITE customer electricity bills for a prolonged period of time. Therefore, return of the revenues via a separate check may be preferable.

represent only a small fraction of total revenue.⁷⁴ We are inclined to agree with the Joint Parties' assessment. Though we are directed to return allowance revenue to small businesses, we do not believe the presence of carbon pricing in electricity rates for small businesses will necessarily result in emissions or economic leakage, excluding those businesses that operate in industries eligible for Industry Assistance. The presence of a carbon price in electricity rates, and the reflection of that cost in the price of goods and services, provides a critical incentive to shift toward economic activities that result in fewer GHG emissions. It is our intent that small businesses should see a carbon price signal in their electricity rates. However, given the direction in § 748.5(a), it is appropriate to provide small businesses with transition assistance to ease small businesses into the Cap-and-Trade program and to provide additional time and capital to help businesses invest in strategies to reduce their exposure to GHG costs.

Aside from a recommendation to volumetrically return all GHG revenues in proportion to Cap-and-Trade program costs incurred, as proposed by the Joint Utilities and DRA, we received few alternate distribution methodology proposals for consideration. However, we find compelling a principle set forth by DRA that small business customers should be compensated in a similar manner to EITE customers. Given that we are viewing the return of revenues to small business customers through the lens of providing transition assistance, we find it appropriate to return GHG allowance revenues to small business customers in a

⁷⁴ Comments of the Joint Parties on the Impact of SB 1018, August 1, 2012, at 5, citing J.Weiss and M. Sarro, *The Economic Impact of AB 32 on California Small Businesses*, prepared by the Brattle Group for the Union of Concerned Scientists, December 2009 (finding that the average small business in California spends less than 1.5 percent of revenues on energy related costs).

manner that mirrors, as much as possible, the transition assistance methodology we adopt for EITE customers, and we direct the utilities to return GHG revenues to small business customers in such a manner.

Whereas our approach to compensating EITE facilities, modeled after ARB's methodology to allocate allowances to Industrial Covered Entities, takes into account each industrial facility's product output and a measure of the facility's emissions intensity, it would be impracticable to replicate and implement such a detailed methodology for each small business in California. Thus, in order to achieve administrative simplicity, and to ensure that the amount of revenue returned declines over time in a similar fashion as the return provided to EITE entities, that, in our view pose a much greater leakage risk, we propose a small business allocation methodology that discounts the amount of GHG costs present in small business electricity tariffs by ARB's low leakage risk Industry Assistance Factor. We believe that the low leakage risk classification is the most appropriate classification to apply in this circumstance given our position that small businesses pose a relatively lower leakage risk as compared to EITE entities.

We lack sufficient record at this time to adopt a specific formula to allocate GHG revenues to small business customers. Therefore, to calculate the amount of GHG allowance revenue to return to small business customers, we propose in Appendix B, but do not adopt, a formula that is a simplification of the approach we propose in Appendix A to compensate EITE facilities. This formula represents a modified volumetric return. We note that the formula relies entirely upon factors and calculations that have been established and publicly vetted in other venues, including by ARB and the utilities' EIRA proceedings. The

formula will be finalized, following a public vetting process, as set forth in Section 6 discussing implementation.

Although our proposed methodology will largely mute the carbon price signal in small business rates during the first compliance period of 2013-2014, in the second compliance period small businesses will see more than half of the carbon price signal in their rates, and in the third program period small businesses will see almost all of the carbon price signal in electricity rates. Though a modified volumetric return conflicts with our primary policy objective of preserving the carbon price signal, this conflict persists primarily during the first compliance period, after which ARB's low leakage risk Industry Assistance Factors decline steeply and small business will begin seeing the carbon price signal to increasing degrees. This approach maintains the carbon signal – albeit a muted one – while also preserving a substantial amount of allowance revenue for households, the partial purpose of which is to compensate households for increased costs of goods and services as a result of Cap-and-Trade.

5.4.2.1. Timing and Mechanics of GHG Revenue Distribution to Small Businesses

Given that we are proposing to return GHG revenues to small business customers on a volumetric basis based upon electricity usage, and given that we anticipate that the average amount of revenue returned to each small business will be small, we find it appropriate that revenues be returned as a monthly volumetric bill credit, as proposed by the Joint Utilities. However, the frequency of return of GHG revenues to small business customers will depend upon the formula ultimately adopted through the implementation process discussed in Section 6. Therefore, we defer a final decision on the timing of distribution of GHG revenues to small business customers to the implementation process.

In keeping with our desire to facilitate customer understanding of GHG revenue return, we direct the investor-owned utilities to present the small business return as a separate line-item on electricity bills. Additionally, this return must be provided on the delivery component of customers' bills in a manner that ensures that small businesses taking service from DA or CCA receive equivalent compensation to their peers taking service from the investor-owned utilities.

5.4.3. Steps 3 and 4: Offset GHG Costs in Residential Rates and Return Remaining Revenues Equally to All Residential Customers

After accounting for compensation to EITE and small business customers pursuant to the methodologies described above (and setting aside an appropriate portion of GHG revenues for customer outreach and education and administrative costs as discussed later in this decision), we find that all remaining GHG allowance revenues, inclusive of interest, should be returned to residential customers. We take a bifurcated approach in allocating these revenues to residential customers in recognition of the inequities that exist among residential customers in terms of a disproportionate allocation of cost burdens that have arisen as a result of the statutorily mandated features of residential rate design.

With this in mind, we direct the investor-owned utilities to first return revenues to residential customers on a volumetric basis in an amount equivalent to, and not exceeding, the Cap-and-Trade-related program costs that are embedded in the applicable residential rates. Although this approach violates our fundamental objective of preserving the carbon price signal, we believe the specific limitations imposed by SB 695 governing the allocation of cost responsibility in residential rates requires an exception. By returning the

revenues in this manner, we intend to insulate residential customers who consume electricity in the upper tiers from bearing additional costs under the Cap-and-Trade program given the disproportionate cost burden upper tier customers currently bear compared to customers on lower tier rates, a circumstance that will be exacerbated under the Cap-and-Trade program. After allocating revenues for this purpose, the remaining revenues shall be returned equally on a per residential account basis (a non-volumetric return) to help defray the indirect costs of the Cap-and-Trade program that will ultimately be borne by residential customers. Implementation details are discussed in Section 6, below.

By providing residential customers with the remaining allowance revenue, returned on a non-volumetric basis, we largely preserve the overall demand for goods and services in the economy, which could otherwise be negatively impacted as increased electricity costs due to Cap-and-Trade result in a corresponding increase in the costs of goods and services. To the extent that consumers receive the value of the GHG allowance revenue and subsequently spend these revenues, the potentially adverse impacts of the Cap-and-Trade program are substantially reduced. Total spending in the economy will be largely maintained, but will be influenced by pricing that more appropriately reflects the real costs of spending decisions on the environment.⁷⁵ As a result,

⁷⁵ In reaching this and subsequent conclusions, we rely heavily on the final report of the Economic and Allocation Advisory Committee: *Allocating Emissions Allowances Under a California Cap-and-Trade Program*, March 2010. The final report was incorporated into the record on July 22, 2011. See *Administrative Law Judge's Ruling Suspending Requests for Alternate Proposals and Comments, Confirming New Prehearing Conference, Confirming Workshop, Encouraging Parties to Complete Pre-Workshop Reading, and Denying Motion for Interim Decision*.

though we do not return revenue to commercial and industrial entities that are not deemed to be EITE (with the exception of small businesses), the revenue returned to households will largely, if not entirely, flow back into the economy, helping to mitigate the overall impacts of the program on demand for the goods and services those businesses provide.

Furthermore, by returning remaining GHG allowance revenue to all residential customers (and not only those that bear direct GHG costs,) we achieve our policy objective of reducing adverse impacts to low-income households. As stated earlier in this decision, low-income households' non-energy expenses will likely increase as a result of the Cap-and-Trade program as medium and large businesses pass through their own Cap-and-Trade-related costs in the price of their goods and services. The impact of these price increases will likely be proportionally greater on lower income households, as these households tend to spend a greater proportion of their incomes on basic goods and services. This reasoning is supported by TURN, among others, which states: "to focus narrowly, at least on the residential side, on the costs solely borne by customers with upper tier usage is to miss the point of greenhouse gas regulation and to ignore...[that] lower-income households will face larger cost increases due to the overall impact of AB 32 regulations as a percentage of their incomes than upper-income households."⁷⁶ More detail on each element of this bifurcated approach is described below.

⁷⁶ TURN Opening Proposal, October 5, 2011, at 3-4.

5.4.3.1. Offset Cap-and-Trade Costs in Residential Rates

Currently PG&E, SCE, and SDG&E use two basic rate volumetric structures for the majority of their customers: time-of-use (TOU) rates and tiered rates. The majority of commercial and industrial customers are on TOU rates. These rates vary by time of day, reflecting the different energy costs during peak and off-peak times. The majority of residential customers are on tiered rates. These rates increase as a customer's usage increases over the course of a billing cycle, applying higher marginal electricity rates to higher-use customers. PG&E, SCE and SDG&E's tiered rates for residential customers generally consist of 4 to 5 tiers, with each tier having a specific price per unit for all energy consumed within that tier. The volume of energy that can be consumed within a given tier is determined based on how that consumption compares to a so-called "baseline," a legislatively defined term that represents an amount of energy consumption intended to reflect 50 to 70 percent of the average energy usage of households in a given climate zone.⁷⁷ For example, PG&E's E-1 (residential) tariff consists of 4 Tiers, with Tier 1 covering energy consumption through 100% of the baseline, Tier 2 covering energy consumption through 130% of baseline, Tier 3 through 200% of baseline, and Tier 4 covering any consumption beyond that.

In 2001, in response to the energy crisis, the Legislature passed AB 1X.⁷⁸ AB 1X effectively froze Tier 1 and 2 rates; therefore, any new expenses incurred

⁷⁷ Each utility service territory is divided into various climate zones, each with a specific baseline amount of energy to reflect climactic differences and resulting energy needs. See <http://www.cpuc.ca.gov/PUC/energy/Electric+Rates/Baseline/baselineintro.htm>.

⁷⁸ Statutes of 2001, Chapter 4.

(and assigned to the residential customer class) since the rate freeze are recovered entirely in upper-tier residential rates. This has resulted in a rate structure such that Tier 1 and 2 rates are well below the average residential rate while upper tier rates far exceed average rates. These differences are exacerbated by the fact that Tier 1 and 2 consumption represents the majority of energy consumed. Any new costs associated with consumption within the usage limits of Tiers 1 and 2 are spread over the relatively few kWh of energy consumed in the upper-tiers resulting in significant increases in upper tier rates. Using PG&E as an example, most Tier 3 and 4 rates effective July 1, 2012, are 59% and 81% higher than the residential average rate, respectively, while Tier 1 and 2 rates are approximately 31% and 21% below the average rate, respectively. Although SB 695 allows for modest increases in rates for Tiers 1 and 2, the annual rate of increase is capped at 5%, and as such provides limited means of mitigating the existing differences between lower and upper tier rates. As described earlier, the limitations on the Commission's ability to assign additional costs to PG&E, SCE, and SDG&E's Tier 1 and 2 rates effectively prevents any Cap-and-Trade-related costs from being reflected in those rates. Therefore, residential customers on lower-tier rates, which represent the vast majority of kWh consumed, will be effectively blind to any carbon price signal and will have no incentive to alter electricity consumption as a result of the Cap-and-Trade program, while customers on upper-tier rates will see a disproportionately strong signal.

This fact was reflected in the Joint Utilities' proposal, which recommended that GHG allowance revenue allocated to the residential sector be used to reduce all GHG costs in upper tier rates only. The Joint Utilities argued that lower tier customers will not experience a carbon price signal. However, the main justification for the Joint Utilities' proposal was the assertion that, due to the

inelastic nature of electricity demand, any carbon price signal in rates will not be significant enough to induce behavioral change among ratepayers, an argument we refuted earlier in this decision. DRA, in its revised proposal after passage of SB 1018, also advocated that GHG allowance revenues be used to reduce upper-tier residential rates; however, DRA argues that allowance revenue should only be used to reduce Tier 3-5 residential rates to the level they would reach if carbon costs could be spread across all residential ratepayers equally. That is to say, DRA supports the inclusion of the Cap-and-Trade-related costs associated with upper-tier usage in upper-tier rates rather than the elimination of all GHG costs, as proposed by the Joint Utilities. The Joint Parties, on the other hand, advocate that GHG costs remain fully present in retail electric rates in order to maintain a carbon price signal.⁷⁹

While our decision to use allowance revenue to eliminate Cap-and-Trade-related costs from residential rates is seemingly at odds with our general preference to preserve the carbon price signal in electricity rates, we believe an exception in the residential rate class is appropriate given the differences in cost burden that exist in tiered rates. As discussed above, upper-tier residential rates are already well above the marginal costs of electricity even absent any GHG costs. To include GHG costs in upper-tier residential rates that are beyond the cost responsibility of customers in these upper tiers is not appropriate. Therefore, we agree with the Joint Utilities that it is appropriate to use GHG allowance revenues to offset all GHG costs in upper-tier residential rates. We disagree with DRA that only GHG costs associated with electricity consumption

⁷⁹ The Joint Parties do support the allocation of GHG allowance revenues to residential customers, but not to reduce GHG costs embedded in residential rates.

in the lower tier rates should be offset in upper-tier rates. Doing so would maintain the existing inequity between lower-tier and upper-tier rates; lower-tier residential customers would still see no price signal, while upper-tier customers would experience a further price increase – an outcome that seems unfair given the strong incentive for conservation already present in upper-tier rates.

In electing to offset all Cap-and-Trade-related costs in upper-tier residential rates, however, we wish to underscore that we are only adopting this approach as a result of the disproportionate costs allocated to upper-tier customers under the current tiered residential rate structure, which would be further exacerbated by the inclusion of GHG costs. Should the differences between lower and upper-tier residential rates be substantially reduced or eliminated, it would no longer be appropriate to use allowance revenue for this purpose. In that event, the carbon price signal should be fully reflected in residential rates and all remaining revenue should be returned on a non-volumetric basis as described below. It is for this reason that we do not authorize an offset of GHG costs in residential rates by the small and multi-jurisdictional utilities (with the exception of Bear Valley); as mentioned earlier, these utilities are not bound by the limitations on cost increases of lower-tier residential rates set forth in AB 1X and SB 695. Therefore, PacifiCorp and CalPeco must skip this step in the allocation of GHG allowance revenue to residential customers. We discuss PacifiCorp and CalPeco's GHG revenue allocation methodology in more detail later in this decision.

Finally, it is important to note that not all residential customers of PG&E, SCE and SDG&E are on tiered rates. Residential customers may choose non-tiered, TOU rates in some circumstances. Importantly, TOU rates are not subject to the same cost-allocation limitations and inequities as tiered rates,

where customers on upper-tier rates must bear the costs resulting from the activities of other customers taking service on lower-tier rates. As a result, customers on residential TOU rates pay prices that more accurately reflect, and are in proportion to, the actual Cap-and-Trade-related costs they are responsible for creating. Thus, viewed only in this regard, there is no compelling policy rationale for offsetting the GHG costs that will be reflected in TOU rates. However, because residential TOU rates are not mandatory, we decline to include GHG costs in residential TOU tariffs. Doing so would require residential TOU customers to bear GHG costs while residential customers on tiered rates would not, and it is not our desire to create a perverse incentive for customers to remain on tiered rates despite the possible advantages that TOU rates would otherwise offer. Therefore, like customers on tiered rates, residential customers on TOU rates shall be compensated for all GHG costs incurred.

**5.4.3.1.1. Mechanics of Residential Rate
GHG Cost Offset**

Because we seek to neutralize the presence of Cap-and-Trade-related costs in residential rates, we find it appropriate to neutralize costs at the time that they are incurred. The Joint Utilities propose returning revenues in direct proportion to costs incurred at the end of each monthly billing cycle. Under this proposal, the utility would calculate costs and apply revenues in a process that would not be spelled out via a separate line-item on bills. Before the passage of SB 1018, DRA initially proposed that revenues be returned on an annual basis to maintain some carbon price signal; however, it appears that DRA's updated proposal reflects the concept of a complete offset at the time costs are incurred. DRA, in its customer education proposal, appears to advocate for separate line-items to appear on customer bills to show GHG costs and revenues.

We adopt the proposal of the Joint Utilities and direct PG&E, SCE and SDG&E to offset GHG costs in residential rates in the monthly billing cycle in which they are incurred. Furthermore, we agree with the Joint Utilities that, at this point, the volumetric GHG cost offset in residential rates should not be highlighted as a separate line-item on bills. While we agree with DRA that it is essential to facilitate customer awareness of GHG costs and the application of GHG revenues, we believe that it will cause confusion to highlight the volumetric offset of GHG costs in residential rates, especially because we mandate the return of all remaining revenues as an on-bill credit that is visible via a separate line-item.

Finally, as described in greater detail in the section discussing CCA and DA customers below, in order to ensure that residential customers of CCAs and Energy Service Providers receive their proportional share of GHG allowance revenues to offset GHG costs in residential rates, we require that allowance revenues be returned to residential customers via a delivery rate component that all residential customers pay (as proposed by the Joint Utilities). In this way, all residential customers, whether taking service as bundled customers or from a CCA or Energy Service Provider, receive a proportional share of the GHG revenue needed to offset the GHG costs allocated to the residential customer class.

In order to implement the volumetric rate offset to residential customers, the utilities will need to calculate GHG costs in residential rates. The process for approving the cost calculation methodology and other implementation details is discussed in Section 6.

5.4.3.2. Return Remaining Revenues on a Non-Volumetric Basis

Once EITE and small business entities are compensated, GHG costs due to the Cap-and-Trade program are offset within residential rates, and allowance revenue is set aside for customer education and general administrative costs (as discussed in more detail below), we direct the utilities to return all remaining GHG allowance revenue to residential ratepayers on an equal, per-account basis. The return will be known as a “climate dividend.” DRA proposed this approach,⁸⁰ and we find this method of revenue distribution to be a reasonable means of ensuring that residential customers (especially lower-income residential customers) are compensated for the likely increase in the price of goods and services as a result of GHG costs being reflected in electricity rates. This approach has the advantage of providing a greater return as a share of income to lower-income households, which, as argued by the Joint Parties, is appropriate given that energy costs in general, and the burden of the Cap-and-Trade program in particular, will fall more heavily on low-income households, as a percent of household income.

We note that the Joint Parties also advocate for the distribution of GHG allowance revenue to all residential customers; however, their recommended approach, which would allocate revenues based upon energy costs for different climate zones, is not necessary given that we are offsetting GHG costs in residential rates at this time. However, the Joint Parties’ proposed methodology raises an important issue regarding the most equitable way of distributing

⁸⁰ Comments of DRA in Response to ALJ’s Ruling on the Impact of SB 1018, August 1, 2012 at 3. TURN also supported a similar methodology (see TURN Opening Proposal, October 5, 2011, at 4).

allowance revenues among residential customers. There are many differences among residential accounts, including size of household and electricity usage (in addition to differences between climate zones, as mentioned by the Joint Parties), and there simply is no way to ensure that revenues are distributed in a manner that recognizes each of these factors. Furthermore, aside from the climate-zone approach offered by the Joint Parties, no other party offered a different distribution methodology for our consideration other than via a per account basis. At this time, we believe that the distribution of all remaining GHG allowance revenue on an equal per residential account basis, as described in more detail below, ensures the most equitable treatment of residential customers available.

5.4.3.2.1 Calculating the Climate Dividend

We must consider several issues that define the climate dividend return to residential customers: (1) how to calculate the amount of revenue to be returned to each residential customer, (2) how frequently revenue should be distributed, and (3) what form the revenue return should take (e.g. on-bill versus off-bill compensation). We first address the method for calculating the revenue return to residential customers.

For reasons set forth above, we find that the GHG allowance revenue amount returned to customers should be calculated on an equal per residential account basis, as proposed by DRA in their updated proposal following passage of SB 1018. The specific amount of revenues to be received by each residential account should be calculated by dividing a utility's allowance revenue (including those associated with CCA and DA customers), net of the revenue set aside to fund customer education and outreach, compensate EITE and small business entities, offset the residential rate impacts of the Cap-and-Trade program, and to

cover administrative costs, by the number of residential accounts taking distribution service from the utility. In pursuing this approach, our intent is to provide revenues on an equal basis, per household, where the number of residential accounts appears to be a reasonable proxy for the number of households. However, in some instances, a single household may have more than one account, for example if they have multiple meters. In calculating the climate dividend, the utilities will need to account for this and adjust their calculations and returns accordingly, as discussed in more detail in Section 6. We also note that this per-account approach may not sufficiently address the unique characteristics of customers taking service via a master-meter, or customers whose electricity charges are less than the GHG revenue return (such as net-metering customers). We address these unique circumstances in more detail below as best we are able given the limited record before us on these matters.

5.4.3.2.2. Form of Climate Dividend Return

We next consider the form of the climate dividend return to residential ratepayers. At a most basic level, there are two alternatives for returning revenues to customers: on customers' bills (on-bill) or separate from customers' bills (off-bill). An on-bill return would be presented as a credit on a customer's bill returned at a regular time interval. This bill credit would then be netted against the customer's bill for that month, with any excess value carried over into subsequent months until it is exhausted. In contrast, an off-bill return, as we use that term here, would be a cash-equivalent payment, for example a physical check sent to each customer, a direct deposit into a customer's bank account or a credit on an electronic benefit card.

DRA and the Joint Parties argue that an off-bill rebate (delivered through a separate payment not included in the customer's monthly bill) is preferable because it is independent of the customer's bill and allows for increased customer understanding of the Cap-and-Trade program. Additionally, an off-bill return avoids the risk that the return might effectively, and unintentionally, mute the carbon price signal if customers perceive an on-bill return to be an additional rate offset. PacifiCorp, the Joint Utilities, TURN and the Agricultural Parties oppose the use of an off-bill rebate, arguing that this approach is administratively complex and costly. PacifiCorp suggests that if the Commission were to use an off-bill rebate, it should allow utilities to use auction revenue to cover the administrative costs of providing the rebate.⁸¹

We share the concern of DRA and others that customers may perceive the GHG allowance revenue return, even if calculated non-volumetrically, as a rate reduction if it is returned via an on-bill credit against each customer's bill. Therefore, from the policy standpoint of preserving the carbon price signal, it is preferable to return revenues separate from customer bills through a check or some other form of off-bill rebate.⁸² As argued by DRA, the Joint Parties, and IEP, customers would essentially receive the revenues as cash or a cash equivalent, wholly independent of their electricity bills; thus, there would be no risk that customers would interpret the refund as a reduction in electricity rates.

⁸¹ We address recovery of administrative costs generally in Section 5.9.

⁸² We note that because we are neutralizing GHG costs in residential rates, there will be no carbon price signal in rates at this time. However, an on-bill return of GHG revenue, depending on the frequency of the return, could have the unintended consequence of dampening other conservation price signals already present in rates from programs such as energy efficiency and the Renewables Portfolio Standard.

Furthermore, residential customers would be able to use the money as they see fit to mitigate the increased costs of goods and services.

However, on closer examination, there are many concerns associated with the adoption of an off-bill rebate methodology. All of the utilities have argued that there is a significant cost and administrative burden associated with the implementation of an off-bill rebate program. SDG&E, for example, offered compelling evidence that the implementation of an off-bill credit would require significant initial (upfront) and recurring costs. Furthermore, there can be significant follow-up costs associated with the issuance of a check. PG&E provides documentation to show that for each check that is not cashed by a residential customer, PG&E (and the other utilities) must engage in a costly and time consuming escheatment process that could dwarf the value of the check itself. Depending upon the percentage of checks that are not cashed, the total cost could approach upwards of \$7 million per year.⁸³

We share the concerns of the utilities that implementation of an off-bill rebate will likely be costly and administratively burdensome. As a matter of policy, we prefer to preserve as much of the allowance revenue value as possible for direct return to customers, and we are aware that our adopted method of return for EITE and small business customers may entail significant administrative costs. Furthermore, in the absence of reliable information on the actual allowance value available for return, (which will be wholly dependent upon allowances prices in any given year), and about the complete costs of different off-bill rebate methods, we are concerned that significant administrative

⁸³ PG&E Filing of Supplemental Information in Response to ALJs' Request, June 1, 2012 at 5.

costs could substantially reduce the amount of revenues available for direct return to residential ratepayers.

Additionally, by applying the return as a credit to customers' bills, we can reduce the risk of customers not receiving the value if, for example, they fail to receive or cash a check, or otherwise use the return. While this concern was not raised by any parties in this proceeding, we find that all residential customers are entitled to their share of GHG allowance revenues, and we are concerned about hastily selecting any process that diminishes the ability of some customers to receive that revenue (for example, through the loss of a check), without further analysis. As a credit, the allowance value will be used directly to pay for electricity, but in doing so it will free up the money the customer would otherwise use to pay that bill to use for other purposes.⁸⁴ In addition, as noted by TURN, on-bill rebates do not necessarily dampen price signals in rates, including conservation price signals separate from the carbon price signal, which will be neutralized in residential rates. Whether an on-bill rebate interferes with price signals may be related to how often the rebate is paid and by what method it is calculated. By ensuring that the rebate is non-volumetric and that it is delivered relatively infrequently (as discussed below), we expect to avoid dampening any additional conservation price signals that exist in residential rates. Therefore, at least initially, we direct the utilities to return the non-volumetric portion of the residential rebate as an on-bill credit against customers' electricity bills. If, at a

⁸⁴ We should note that in circumstances where the credit value exceeds the energy costs of a household we do run the risk that the credit will result in additional energy consumption and/or stranded value. This might occur for some households that, due to net energy metering, have effectively zeroed-out their bills, or reduced their bills such that the annual credit amount exceeds their annual electricity costs. We address this issue below.

later date, it is found that an off-bill approach achieves substantially greater customer understanding of the Cap-and-Trade program or administrative costs can be substantially reduced, we may reconsider whether an off-bill return is appropriate.

Finally, to ensure equitable treatment of residential customers irrespective of whether they are bundled customers of a utility or take service under a CCA or from an Energy Service Provider, the on-bill credit should be provided to all households taking distribution service from an investor-owned utility. To address MEA's concern that rebates returned to CCA customers (and DA customers) will be perceived as a windfall from the investor-owned utilities, rather than as a benefit of state policy, we require that the rebate be listed on utilities' bills as a separate line item, and the utilities must provide additional company-neutral information to ratepayers about the Cap-and-Trade program, as discussed in the section on customer outreach and education, below.

5.4.3.2.3. Frequency of Climate Dividend Return

In regard to the frequency of the return of the climate dividend to residential customers, we are guided by our desire to make the rebate meaningful and understandable while minimizing interference with the conservation price signals currently in rates. A monthly return, as proposed by the Joint Utilities, would likely be minimal and could possibly go unnoticed by customers. Furthermore, a monthly bill credit would seem to run the risk of giving individuals the false sense that electricity rates have actually decreased under the Cap-and-Trade program, potentially leading to increased electricity consumption. However, we must balance these concerns against our desire for

residential customers to receive their share of allowance revenues in a timely manner.⁸⁵

Weighing all of these factors together, we find it reasonable that remaining GHG allowance revenues be returned to residential customers on a per-account basis semi-annually (every six months), commencing no sooner than six months from the start of the Cap-and-Trade program (January 1, 2013). While not proposed by any party in this proceeding, we believe that a semi-annual return reflects the best balance of providing a meaningful return to residential ratepayers while not unduly burdening such customers with a prolonged exposure to the higher costs of goods and services, which could result in an unintended dampening effect on consumer spending in the economy. We acknowledge that, in certain circumstances, the climate dividend could exceed a customer's monthly bill. In this case, we envision that any remaining climate dividend in excess of that customer's monthly bill would be applied to the subsequent month's bill until the climate dividend was exhausted. This approach may require some nuanced treatment, for example if a customer moves out of the utility's service territory or the semi-annual climate dividend exceeds a customer's bill for the entire 6-month period in which the climate dividend may be applied before receipt of the next climate dividend. Therefore, we require the utilities to address this issue further as set forth in Section 6.

⁸⁵ This position contrasts with our position that EITE customers should receive revenues after a given Cap-and-Trade program year has passed. We believe EITE customers, as business entities, are better positioned to account for and respond to a delay in receipt of revenues than residential customers.

5.4.4. Net-Metering and Master-Meter Customers

Our adopted GHG revenue distribution methodology has certain implications for customers who receive electricity service under a master-meter configuration and customers who participate in net energy metering. In their June 1, 2012 filings providing supplemental information, PG&E and SCE assert that GHG revenues must be distributed to master-meter customers according to the provisions of § 739.5 (a) and (b), which set forth rules on the rates at which master-meter customers must be billed and the proper methodology for dispersal of any utility credit to master-meter customers.

We agree, and we find that our adopted GHG revenue distribution methodology should allow for the equal treatment of master-meter customers. In the case of the volumetric GHG cost offset for residential rates, master-meter customers' bills will be offset in proportion to GHG costs incurred; therefore, master-meter customers will be treated equally to all other residential customers. This will also be the case for master-meter customers that qualify as small businesses under the definition adopted in this decision.

The climate dividend does pose a potential problem in terms of equitable treatment of residential master-meter customers. As explained earlier in this decision, while we cannot account for all forms of equity in our distribution methodology, and our adopted methodology allocates GHG revenues equally across residential accounts irrespective of the number of electricity users per account, a possible disparity may exist between the number of residents in the average household and the number of customers receiving service under a master-meter configuration. For example, it may be problematic to return the same amount of revenue to a residential account with, for example five electricity users as to a master-meter account with many more customers.

It is our intent that residential master-meter customers receive their proportional share of the climate dividend. At this time, however, we have no record on which to address this potential inequity or to determine the number of customers on a master-meter that tips the scales toward inequitable treatment. Therefore, an additional process will be necessary to address this issue, as discussed in more detail in Section 6.

Customers that participate in net energy metering may not have any balance owed to the utility against which to apply the climate dividend. We have no record in this proceeding to assess the magnitude of this concern or on which to base a solution to address this circumstance. Nonetheless, we find it appropriate to adopt an interim cash-out provision for these customers in a similar vein to the net surplus compensation provisions adopted in D.11-06-016. However, rather than allowing for a cash-out option only when an excess of kWhs of electricity is generated over a 12-month true-up period, as provided for in D.11-06-016, we find it more appropriate to allow for a cash-out provision for instances in which the dollar value of bill credits would otherwise be stranded if the value exceeds the bills a net-energy metering customer faces over the 12-month period following the month in which the credit is applied. In Section 6, we direct the utilities to present an implementation plan for providing cash value to net-energy metering customers according to the interim methodology adopted above. The Commission may wish to update this interim methodology in the future.

5.5. GHG Allowance Revenue Distribution Methodology for Small and Multi-Jurisdictional Utilities

As discussed above, PacifiCorp, Bear Valley, and CalPeco (the small and multi-jurisdictional utilities) are differently situated than PG&E, SCE, and

SDG&E. Significant differences from the larger utilities include not only size but also customer mix (few if any industrial customers, and a higher proportion of part-time residential customers) and customer location (in relatively small and often mountainous areas). In addition, these utilities have fewer customers over which they may spread any administrative or implementation costs of new programs, and, especially in the case of Bear Valley, they expect to receive relatively small amounts of allowance revenue. Finally, small and multi-jurisdictional utilities are not subject to the same statutory restrictions imposed by SB 695 on residential rate increases; therefore all residential rates (including Tier 1 and 2 rates) will reflect the full price of carbon, and no one class of residential ratepayers will bear disproportionate GHG costs in relation to any other class.

Nevertheless, both PacifiCorp and CalPeco expect to receive annual GHG allowance revenue of more than \$2 million each, and both acknowledge that they are capable of returning revenue directly (and non-volumetrically) to residential customers through bill credits, which they can target either by customer class or, failing that, by rate schedule. Therefore, PacifiCorp and CalPeco are directed to return revenues according to the same general methodology as adopted for PG&E, SCE, and SDG&E (including implementation of a customer education program) with one exception. Because all residential rates will reflect the carbon price signal, PacifiCorp and CalPeco will not need to offset GHG costs in residential rates to address the same disproportionate allocation of costs faced by residential customers on tiered rates in the three large investor-owned utilities' service territories. Thus, after compensating EITE and small-business customers, PacifiCorp and CalPeco are directed to return all remaining GHG allowance

revenues equally to residential customers on an equal per-residential account basis.

Bear Valley, as discussed earlier, will receive a *de minimis* amount of allowances under the Cap-and-Trade program and the administrative costs of distributing GHG allowance revenues according to the methodology we adopt for the other investor-owned utilities would far exceed the value of the allowances received. Although we are generally guided by a desire to maintain the carbon price signal for all utility customers, we acknowledge that the benefit of maintaining the carbon price signal in this case would place a disproportionate cost on Bear Valley's ratepayers. Therefore, we adopt Bear Valley's GHG allowance revenue allocation proposal: Bear Valley shall return 100% of GHG allowance revenues, including interest, on a volumetric basis to its customers through its existing, annual Power Purchase Adjustment Clause proceeding. If Bear Valley's customer base increases significantly in size or estimated allowance revenues increase substantially in the future, we may reconsider whether a different distribution mechanism is appropriate at that time.

5.6. Allocation of GHG Allowance Revenue to CCA/DA Customers

The primary interest of DA and CCA customers is to ensure fair and equitable treatment under any GHG revenue allocation methodology pursuant to the Cap-and-Trade regulation § 95892(d)(4), which states that investor-owned utilities "shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators." No party in this proceeding disagrees with the premise that DA and CCA customers should be treated equally under any GHG revenue allocation scheme, and our adopted GHG allocation methodology comports with the parameters of § 95892(d)(4).

CCA representatives are primarily concerned with the mechanics of any adopted volumetric GHG cost offset in residential rates. CCSF and MEA are concerned that the Joint Utilities' volumetric return proposal, which we essentially adopt as our model for offsetting GHG costs in residential rates, unfairly withholds GHG allowance revenue from lower-tier residential customers who will bear GHG costs as a result of the addition of a conservation adjustment mechanism (the Conservation Incentive Adjustment) approved in D.11-05-047 and the implementation of flat generation and distribution components. MEA and CCSF are concerned that the proposal of the Joint Utilities will create a disparity between the lower-tier generation rates of investor-owned utilities and CCA generation rates because the lower-tier rates for investor-owned utility customers are effectively frozen. The Joint Utilities argue that, due to the application of the Conservation Incentive Adjustment, while Tier 1 and 2 customers will experience no increase in their total rates (and thus effectively bear none of the burden of Cap-and-Trade program costs,) the generation component of their rates will increase, as will the generation component of all tiers due to GHG costs. However, the Conservation Incentive Adjustment applies adjustment factors to the distribution component of each rate tier. Thus, while GHG related costs will increase the generation component of Tiers 1 and 2 residential rates, these increased generation rates will be offset by a corresponding decrease to the Tier 1 and 2 distribution component of these rates, resulting in a zero net change to the total rate.

In adopting our methodology for allocating GHG allowance revenues, we intend for CCA and DA customers to be treated equally to the customers of the investor-owned utilities at all times. In this regard, there should be absolutely no difference between the way any revenue is allocated between a bundled

customer and a customer of the CCA or Energy Service Provider. We believe that the disagreement regarding generation charges and GHG costs for Tier 1 and 2 customers is essentially one of semantics. Currently, given the effective rate freeze as a result of SB 95, while all Tier 1 and 2 customers will see an increase in generation charges as a result of the Cap-and-Trade program, including customers of the Joint Utilities, such charges will be entirely offset by the application of the Conservation Incentive Adjustment, as explained by the Joint Utilities. Therefore, no particular residential customer will be treated differently or unfairly as a result of the Cap and Trade program and the flattening of generation charges adopted in D.11-05-047. In addition, to ensure competitive neutrality, GHG compliance costs must be included in the generation component of customers' rates and allocated in the same manner that other generation costs are allocated to bundled customers.

Under our GHG revenue allocation methodology, the investor-owned utilities are directed to return revenues to CCA and DA customers using the same methodology as adopted for those utilities' bundled customers. After compensating EITE and small business customers using the methodology adopted above, all GHG costs for upper-tier residential customers will be refunded volumetrically on a cents per kWh basis each month to offset GHG costs accrued that month, whether residential customers procure energy from a CCA or an investor-owned utility. We have elsewhere clarified that this offset will not occur as a separate marked line-item on bills, and the investor-owned utilities must distribute such GHG revenues through the appropriate distribution component of customer bills to CCA and DA customers.

However, in implementing this requirement, we must further clarify what dollar per kWh amount (volumetric return) the investor-owned utilities should

apply to CCA and DA customers for the respective allocations we have authorized herein. When we described the methodology that the investor-owned utilities will apply to determine what dollar per kWh volumetric offset will be applied to residential customers and what modified volumetric credit will be applied to small businesses, we specified that the amount of the offset and credit should be based on the actual Cap-and-Trade-related costs present in the investor-owned utilities' respective tariffs. These Cap-and-Trade-related costs are dependent on the investor-owned utilities' energy procurement costs that are reflected in the generation component of electricity tariffs. It is natural that CCA and DA providers will have different Cap-and-Trade-related costs than the local investor-owned utility that provides distribution service to CCA and DA customers. Because these costs will differ, it would be irrational and inequitable to compensate CCA and DA customers for Cap-and-Trade-related costs for total kWh sales in a given tariff class that are in excess of the local investor-owned utility's costs apportioned to that same tariff.

If we are to ensure that CCA and DA providers are not disadvantaged relative to investor-owned utilities, and, conversely, that CCA and DA providers are not perversely incented to procure highly-emissive energy, we clarify that the dollars per kWh magnitude of the volumetric return that the investor-owned utilities provide to residential and small business CCA and DA customers must be equivalent to the magnitude of the volumetric return provided to corresponding customers of the investor-owned utilities.⁸⁶ As a result, residential and small business customers will receive the same volumetric GHG

⁸⁶ It is important to note that the allowance allocation the utilities received was based on the emissions associated with the electricity consumed by all customers of the distribution utility, inclusive of CCA and DA customers.

cost offset regardless of whether they procure energy from an investor-owned utility or CCA or DA providers.

All remaining revenues, minus those set aside for customer education and administrative costs, must then be distributed semi-annually on an equal per-residential account basis across all residential CCA and DA customers, as described in detail in preceding sections (and according to the same schedule). Similarly to customers of the investor-owned utilities, CCA and DA customers should see the climate dividend as a separate line-item on customer bills.

5.7. Investment in Energy Efficiency and Clean Energy

Many parties in this proceeding, including the Joint Parties, SEIA, DRA, GPI and others, argue that investment in AB 32 programs, such as energy efficiency or clean energy, is vital to the efficacy of the Cap-and-Trade program, it supports customers in a more targeted manner than the diffuse return of GHG allowance revenues to all customers (as proposed initially by the Joint Utilities), and it allows for maintenance of some, if not all, of the carbon price signal in rates. In addition, § 748.5(c) permits the Commission to allocate up to 15% of GHG allowance revenues toward such programs, although allocation of revenues is not required.

Parties in support of investment in energy efficiency and/or clean energy programs offered a wide variety of options for our consideration including directing revenues to defray the cost of development and interconnection of renewable energy resources or toward various residential, commercial and industrial energy efficiency projects. The Efficiency Council, for example, argues that investment in energy efficiency should be a priority because it follows California's loading order and is the cheapest, fastest, and most direct way to reduce GHG emissions. The Joint Parties point to the experience of the Regional

Greenhouse Gas Initiative, which apportioned a significant portion of their GHG revenues toward energy efficiency projects and programs that are expected to deliver net savings for ratepayers.

While such arguments have merit, we are not persuaded that it is appropriate to direct GHG allowance revenues towards energy efficiency or clean energy programs at this time. GHG allowance revenues represent a previously unavailable source of money that could be used to fund many programs; however, as articulated by TURN, the funds do not represent “free money.”⁸⁷ The revenues created will come directly from the pockets of California ratepayers, many of whom will bear increased retail electricity costs as a result of rising wholesale electricity prices that include the price of carbon. While parties offered several interesting programs and projects for consideration, none are developed to the point that they could be readily and easily implemented within the confines of this proceeding. Furthermore, while several parties envisioned a process whereby the Commission would set-aside a portion of funds and then open a second phase of this proceeding to specifically apportion the funds to various programs, we feel such a process is inappropriate, could be duplicative of existing proceedings, and may result in programs and projects being subject to different evaluation criteria, depending on the proceeding in which such programs are presented.

The appropriate venue for deciding the manner in which GHG revenues should be allocated toward energy efficiency and clean energy programs is within the various proceedings specifically opened to make such decisions. As stated by TURN, “the appropriate way to consider new initiatives is to first

⁸⁷ TURN Opening Comments, January 31, 2012, at 2.

assess current programs and determine where gaps exist that could prevent the state from meeting its established energy and environmental policy goals.”⁸⁸ This Commission, and indeed the State of California, has a long history of aggressively pursuing various AB 32 complementary policies, and nothing in this decision should be construed to mean that we have in any way lessened our firm commitment to these programs and policies.

Furthermore, nothing in this decision precludes us from evaluating specific proposals within the appropriate proceeding and deciding in that proceeding that funding would best come from GHG allowance revenues. Parties are therefore encouraged to bring such proposals and requests for increased funding for energy efficiency and clean energy to the appropriate proceedings where they can be evaluated against all other proposals and within the confines of the greater budgets of those programs. At this time, we feel the most appropriate use of GHG allowance revenue is to return 100% of such revenue directly to those ratepayers that are impacted by increased electricity prices as a result of Cap-and-Trade program and cannot pass those costs through. Finally, we would need to weigh the benefit of directing GHG allowance revenues toward energy efficiency or clean energy programs against the reduction in GHG allowance revenue that will ultimately be returned to residential ratepayers to address the increased costs of goods and services as a result of the inclusion of GHG costs in retail electricity prices.

⁸⁸ *Id* at 3.

5.7.1. Guidelines for Investment of GHG Revenues in Energy Efficiency and Clean Energy Programs

DRA, in its opening comments on the impact of SB 1018, recommends that the Commission adopt criteria for evaluating which energy efficiency or clean energy programs or projects should qualify to receive GHG allowance revenues. We do not have adequate record in this proceeding on which to adopt any criteria, aside from the requirement that any funding be additional to already existing program budgets as set forth in Section 5.3.3.3. However, if, at a later date, the Commission elects to direct funds toward energy efficiency and/or clean energy, we recommend that any program or project funded with GHG allowance revenues have as a primary goal the reduction of GHG emissions. While ultimately all energy efficiency and clean energy projects and programs can result in the reduction of GHG emissions, we find it appropriate to require GHG emissions reductions as a stated (and measurable) goal of a project in order to receive funding via GHG allowance revenues.

5.8. Customer Education

Section 748.5(b) requires the adoption and implementation of a customer education program by January of 2013 to maximize public awareness of the distribution of GHG allowance revenues to ratepayers. As discussed earlier, the Joint Utilities argue that each utility should be able to administer its own education program, and the program should provide consistent and objective information to customers using existing communication channels. Furthermore, they argue, the adopted program should be low cost with modest goals. PacifiCorp supports the Joint Utilities' position that each utility should be responsible for its own customer outreach and education program. Many other parties, such as DRA and the Joint Parties, support customer outreach and engagement, although they differed on the type of information that should be

conveyed and the role of the adopted GHG revenue allocation methodology itself in facilitating customer understanding. Finally, MEA argues that customer outreach and education should be competitively neutral (and therefore administered by an entity other than the utilities), and DACC believes that DA customers have no need for educational programs offered by the utilities; customer education, if needed, should be the responsibility of the Energy Service Provider billing the DA customer.

Given the late date of the passage of SB 1018 and our subsequent issuance of this decision, we agree with the Joint Utilities that the initial customer outreach and education program will have to be modest and targeted for 2013 until the Commission decides a more expansive program is justified.⁸⁹ Furthermore, while customer understanding of the costs and benefits of the Cap-and-Trade program is important, we also seek to maximize the amount of GHG allowance revenues returned customers. Therefore, any and all customer outreach and education in 2013 and beyond must be weighed against the cost of such outreach in order to maximize both customer awareness and GHG allowance revenue returns to ratepayers. Finally, we agree with MEA that customer education and outreach should be competitively neutral. The Cap-and-Trade program is a program of the State of California, and no utility should achieve a competitive advantage over DA and CCA providers as a result of the adoption and implementation of outreach and education plans required by this decision or the methods by which allowance revenues are returned to ratepayers.

⁸⁹ Future utility customer outreach and education plans and budgets will be adopted through an application process discussed in Section 6.

With these guiding principles in mind, we adopt an interim customer education and outreach program for 2013 and lay the foundation for a potentially expanded customer outreach and education program in 2014 and beyond. Given the short timeframe in which to implement a customer education program for 2013, all utilities, including CalPeco and PacifiCorp, shall be responsible for administering the adopted customer outreach and education program on behalf of their own bundled customers as well as their DA and CCA customers. At this juncture, it is infeasible to delegate customer outreach responsibilities to a third-party administrator, and concerns about neutrality can be addressed in other ways, as described in more detail below. Given the *de minimis* amount of GHG allowance revenues to be received by Bear Valley in comparison to the cost of a customer education program, Bear Valley is exempt from implementing any customer outreach and education at this time.

5.8.1. Calendar Year 2013

For calendar year 2013, we adopt a competitively neutral interim customer outreach and education program to be administered by the utilities on behalf of all customers, including CCA and DA customers. The program shall, at a minimum, consist of targeted outreach to all customers that will receive GHG allowance revenues, including EITE and small business customers.⁹⁰ The goal of the interim outreach program is to notify and explain to recipients of allowance revenue that they are receiving a credit as a result of California's GHG Cap-and-Trade program. Such outreach can occur through various channels including bill notices, websites, direct customer outreach and various media outlets. Outreach

⁹⁰ Customer outreach and education in 2013 may also target customers who will not receive GHG allowance revenues, budget permitting.

efforts must ensure that hard-to-reach customers receive adequate information and education. This may be achieved through the use of ethnic media and community based organizations, among other options. Outreach must occur in advance of and concurrent with the distribution of any GHG allowance revenues.

In order to maintain competitive neutrality, we require that the utilities develop messaging that does not in any way advantage the utility over DA and CCA providers. We envision that all references in marketing materials pertaining to GHG allowance revenue returns be attributed to the State of California or the State of California's Cap-and-Trade Program, although utilities may use their logos on such materials. Any communications from the investor-owned utilities to CCA and DA customers pertaining to the distribution of GHG allowance revenues or the Cap-and-Trade program must include the logos of both the investor-owned utility and the CCA or DA provider.

For this interim period, we authorize the utilities to develop the content and messaging of the general outreach and education activities. However, the scope, timing and activities of the utilities' proposed outreach and education activities must ultimately be approved by the Commission as specified in the Implementation section that follows. Furthermore, CCA and DA providers must have the opportunity to review the utilities' 2013 customer outreach plans prior to the filing of plans for approval, as provided in Section 6. The utilities will, upon request from the Director of the Energy Division, distribute to their customers communications from the Commission providing information about the Cap-and-Trade program. These communications must be absent any utility

logo.⁹¹ The timing of such communications will be at the election of the Director of the Energy Division, and the costs of the communications will be funded through the utilities' customer outreach budgets approved below.

We envision the above adopted guidelines and parameters for calendar year 2013 to be a stepping stone toward a more robust and comprehensive customer outreach and education program in the future. We outline the very basic components of customer education in subsequent years in the following section.

5.8.2. Calendar Year 2014 and Beyond

For 2014 and beyond, we seek to expand awareness about the purpose and value of GHG allowance revenue. To facilitate this expansion, by April 1, 2013, we direct the utilities, in consultation with CCA and DA providers, to engage a firm with marketing and public relations expertise that will be responsible for proposing expanded customer education activities through 2015. The marketing and public relations firm must also evaluate the feasibility and potential advantages and disadvantages of the use of a third-party administrator for customer outreach and education activities. The final scope of work must be developed in consultation with and approval by the Director of the Energy Division in advance of the release of any documents soliciting offers, and the final hiring decision must be approved by the Director of the Energy Division. The cost of the consultant is not to exceed \$500,000, with the costs to be borne by each PG&E, SCE, and SDG&E in proportion to their percentage of retail sales.

The consultant shall submit a final report of its research and recommendations to the investor-owned utilities, CCA and DA providers, and

⁹¹ These communications may be included within customer bills.

the Director of the Energy Division no later than July 1, 2013 for use in developing the utilities' customer outreach and education plans for 2014-2015, as set forth in Section 6, below. The report must also be served on the service list of this proceeding, R.11-03-012.

5.8.3. Customer Outreach and Education Budget for 2013

For calendar year 2013, PG&E, SCE and SDG&E proposed initial budgets of \$1.7 million, \$1.4 million and \$ 750,000, respectively.⁹² No party commented on these proposed budgets, and PacifiCorp and CalPeco did not offer budgets for our consideration. Given the nascent state of both the Cap-and-Trade program and of customer outreach and education activities, we find it difficult to evaluate the appropriateness of PG&E, SCE, and SDG&E's proposed budgets. However, absent an alternative, for 2013 we authorize each utility to budget an appropriate amount of funds to achieve the outreach and education goals adopted above. We expect that, for PG&E, SCE, and SDG&E, the interim customer education and outreach budget should not exceed \$1.7 million, \$1.4 million, and \$750,000, respectively. These budgets do not include the costs of the consultant that we have directed the utilities to engage to evaluate longer-term customer education and outreach activities, which shall also be appropriately paid for with GHG allowance revenues.

PacifiCorp and CalPeco are also authorized to expend the necessary funds to undertake customer outreach efforts. Because PacifiCorp and CalPeco did not propose customer outreach budgets for 2013, we rely upon the budgets offered

⁹² The Joint Utilities state that these budgets are based upon the use of bill inserts, online communications, earned media and direct one-to-one outreach to customers whose bills will be significantly, negatively affected by SB 1018 but do not include any mass media or direct mail outreach to all customers.

by PG&E, SCE, and SDG&E. PG&E, SCE, and SDG&E's proposed customer outreach budgets represent approximately 0.4% for SCE, 0.7% for PG&E and 1.1% for SDG&E of total GHG allowance revenues for each utility in 2013, using the ARB allowance floor price. There are likely to be economies of scale involved with the administration of a customer outreach program, as evidenced by the fact that SCE's proposed outreach budget represents a smaller percentage of its estimated 2013 GHG revenues than does PG&E's proposed budget, which is a smaller percentage than SDG&E's proposed budget. It is reasonable to expect that PacifiCorp and CalPeco's customer outreach and education expenses for 2013 will represent around the same percentage of their respective allowance revenues for 2013 as SDG&E's expenses, because SDG&E is the smallest of the three large investor-owned utilities. However, some cushion is appropriate in recognition of economies of scale enjoyed by the larger utilities, including SDG&E. Thus, PacifiCorp and CalPeco are authorized to budget up to 1.5% of their expected allowance revenue at the 2013 ARB floor price for customer outreach and education expenditures in 2013, which yields budgets of approximately \$110,000 for PacifiCorp and \$35,000 for CalPeco.

The utilities are authorized to track costs related to customer outreach in a memorandum account, and expenditures shall be reviewed for reasonableness. As noted earlier, we find that all customer outreach and education efforts deployed pursuant to § 748.5(b) are appropriately paid for out of GHG allowance revenues. In order to ensure that adequate funding is available, each utility is directed to set aside a portion of the GHG allowance revenues to fund customer outreach before distribution of any funds to EITE, small business, and residential customers. Any remaining customer outreach and education funds at the end of a calendar year must be rolled over for use in subsequent years.

5.9. Administrative Costs

In response to an ALJ request for supplemental information, PacifiCorp requested that, should an off-bill rebate option be adopted for the return of GHG revenues to residential customers, PacifiCorp be allowed to use GHG revenues to cover administrative costs associated with implementation. While we ultimately elect to return revenues via an on-bill credit, PacifiCorp's request highlights an overarching issue regarding administrative costs to implement our adopted GHG revenue allocation methodology. Our adopted methodology may require system and billing upgrades in order to track GHG costs and revenues as well as ongoing administrative costs to distribute revenues to the appropriate customer groups. The three large investor-owned utilities have provided rough estimates of administrative costs associated with various residential revenue return methodologies; however, we have no estimate of all administrative costs that will be incurred in order to implement our adopted GHG revenue allocation methodology.

Similar to our reasoning regarding costs associated with customer outreach and education, we find that all necessary administrative costs to implement our adopted GHG allocation methodology should be recovered from GHG revenues. The utilities, with the exception of Bear Valley, are required to provide detailed forecasts of costs to be incurred in 2013 and subsequent years, as described in Section 6, below, and the utilities are authorized to track administrative costs in a memorandum account. Administrative expenditures will be reviewed for reasonableness. In order to ensure that adequate funding is available, each utility is directed to set aside a portion of the GHG allowance revenues to cover administrative costs before distribution of any funds to EITE,

small business, and residential customers. Any remaining administrative funds at the end of a calendar year shall be rolled over for use in subsequent years.

5.10. Additional Issues

5.10.1. BART

As stated in opening comments, BART requests an allocation of GHG allowance value to make up for the difference between its own compliance obligation and the allowance value it would receive under the Joint Utilities' proposal, which is based upon PG&E's specific resource mix. DACC argues that BART acts essentially as a direct access customer, purchasing power primarily from the Northern California Power Agency. Therefore, BART would face the same mismatch in received allowance value as any DA or CCA customer. In such a situation, the cost of acquiring allowances to meet the compliance obligation of any energy service provider or CCA will differ from GHG allowance revenue received from the investor-owned utility, in BART's case, PG&E. DACC argues that specifically identifying and verifying each Energy Service Provider and CCA's carbon profile for allocation purposes and including it in the allocation calculation would be administratively burdensome.

We agree with DACC that BART acts, essentially, as a DA customer and therefore should not receive any special set-aside or additional allocation of GHG allowance revenue. Furthermore, under the definitions adopted today, BART cannot be classified as either an EITE or small business customer; therefore, it is prohibited from receiving GHG allowance revenue. While we acknowledge that BART provides a low-carbon alternative transportation option, which is in accordance with the goals of AB 32, we do not believe BART is uniquely situated when compared to other un-bundled PG&E customers, such as DA and CCA customers. Furthermore, the existence of a cap on GHG emissions and a

resulting carbon price has been part of utility power purchasing calculations for several years in anticipation of the implementation of a cap-and-trade program. Under these circumstances, BART has had (and retains) the ability to weigh various costs and benefits, including the potential cost of carbon, when choosing to purchase power from an electric provider other than PG&E.

6. Implementation

There are many implementation details that must be addressed related to the utilities' administration of our adopted GHG allowance return methodology. Below, we set forth the processes that shall be followed by the utilities and Energy Division staff to fully implement all outstanding aspects of our adopted methodology. Implementation details shall be finalized in a third phase in Track 1 of this proceeding.

6.1. Authority to Track GHG Costs and Revenues and Recovery of Costs in Rates

In their initial GHG revenue allocation proposal, PG&E, SCE, and SDG&E propose that GHG costs and revenues be recovered in rates based on an ERRA forecast approved by the Commission, which would be adjusted through the use of balancing accounts. PacifiCorp and CalPeco request similar treatment through their Energy Cost Adjustment Clause mechanisms. However, with the exception of Bear Valley, we defer including in rates both GHG costs and revenues, including interest,⁹³ for all retail customers until necessary implementation details of our adopted GHG revenue allocation methodology are resolved. GHG costs for each compliance year are the GHG compliance costs incurred directly by the utilities for GHG emissions from their own facilities,

⁹³ Interest shall be accrued at the standard Commission-approved interest rate traditionally used for accruals in balancing accounts.

contracts where they have assumed the cost of compliance on behalf of a third-party (either agreeing to compensate the third-party for the costs of their compliance obligations or where the investor-owned utility is responsible for procuring allowances on the third-party's behalf), or associated with electricity imports where the investor-owned utility is the compliance entity. In addition, GHG costs are the GHG compliance costs incurred by the utilities through the GHG costs of electricity purchased in the wholesale market. GHG costs must be deferred based upon approved 2013 cost forecasts in each utility's 2013 ERRR or Energy Cost Adjustment Clause proceedings.

If GHG-related energy costs were immediately recoverable in rates before the GHG revenue allocation methodology is implemented, retail customers eligible to receive GHG allowance revenues would see only the cost increase without receipt of any countervailing revenues. Therefore, PG&E, SCE, and SDG&E, PacifiCorp and CalPeco are directed to record estimated GHG costs for subsequent recovery in rates in a new GHG sub-balancing account. Estimated GHG revenues must be recorded and deferred for now in a new GHG Revenue Balancing Account.

At the point that the Commission designates that the adopted GHG revenue allocation methodology is implemented, which shall occur upon issuance of a written letter by the Director of the Energy Division that shall be served on the service list of this proceeding (following the adoption of necessary decisions addressing implementation, as set forth in Section 6), the utilities may simultaneously begin the prospective allocation of GHG-related costs to all customers and provide GHG revenues to eligible customer classes. The outstanding cost and revenue balances accumulated in the GHG sub-balancing account and the GHG Revenue Balancing Account must then be amortized over

a reasonable period so that all deferred costs are recovered and all deferred revenues are distributed within 24 months.⁹⁴

As noted in opening comments on the proposed decision by MEA, we acknowledge that the deferral of GHG costs for the investor-owned utilities could create a temporary competitive disadvantage between the investor-owned utilities and CCAs because the investor-owned utilities' generation costs will be lower compared to a CCA that passes through GHG costs in rates. This same disadvantage extends to DA customers, as noted by DACC in reply comments to the proposed decision. However, as stated by SCE and PG&E in reply comments, although we cannot order them to do so, CCAs and Energy Service Providers could elect to defer the inclusion of GHG costs for the duration of the deferral of the investor-owned utilities' GHG costs.⁹⁵ Furthermore, as stated by SCE in reply comments,⁹⁶ if CCA (and DA) providers choose to immediately include GHG costs in rates, any competitive disadvantage will be offset by the competitive disadvantage experienced by the investor-owned utilities once they begin to amortize deferred GHG costs in rates.

Therefore, the deferral of GHG costs in rates pending finalization of implementation details does not violate the Cap-and-Trade regulation's requirement of equal treatment by the investor-owned utilities of their own customers and the customers of CCAs and Energy Service Providers.⁹⁷ However,

⁹⁴ A 24-month amortization period will avoid any financial reporting requirements, which would be triggered by an excessive delay in recovery.

⁹⁵ Reply Comments of PG&E, December 11, 2012, at 2. Reply Comments of SCE, December 11, 2012, at 2.

⁹⁶ Reply Comments of SCE, December 11, 2012, at 2.

⁹⁷ 17 CCR § 95892(d)(4).

to ensure accurate representation of rates to customers, we require that any communication of existing investor-owned utility rates to customers shared by the investor-owned utility and a CCA or Energy Service Provider accurately disclose their respective deferred GHG costs in order to provide a direct comparison.

The utilities are directed to file a Tier 1 advice letter within 30 days of the effective date of this decision establishing the GHG sub-balancing account and GHG Revenue Balancing Account. The establishment of memorandum accounts to track customer outreach and administrative costs is addressed in Section 6.1.1.1, below.

6.1.1. GHG Cost and Revenue Forecast and Reconciliation Proceeding

As described earlier, the utilities request that GHG costs be recovered in rates through their ERRAs, or related proceedings for PacifiCorp and CalPeco. Given the nascent state of the Cap-and-Trade program and the magnitude of GHG revenues, we find that, at least for the initial years of the Cap-and-Trade program, it is prudent to take a more comprehensive and detailed approach conducted outside of ERRA (or related proceedings for PacifiCorp and CalPeco) to forecast and reconcile GHG costs and revenues. Forecasting and evaluation should extend to customer education and administrative costs.

For the first three years of the Cap-and-Trade program, the utilities, with the exception of Bear Valley, must file an application by August 1 of each year beginning in 2013 setting forth forecasted GHG costs for the subsequent year and estimating GHG revenues to be distributed to eligible customer classes. The utilities must also forecast administrative and customer outreach expenses for the subsequent year. These applications may be consolidated to facilitate

consistency in policy and process and allow for the efficient participation of interested parties such as TURN and DRA.

Beginning in 2014, the applications must also include a detailed accounting of actual GHG costs incurred for the previous year as well as revenues distributed to eligible customers classes.

The utilities must also present realized administrative and customer outreach and education costs. Customer outreach and administrative costs shall be subject to reasonableness review because detailed forecasts of these costs have not been provided and such costs will likely be highly unpredictable in the early years. The methodology the utilities will use to calculate realized GHG costs against which to apply revenues (for those customers receiving a volumetric return) must be established given that it will be practically infeasible to determine actual GHG costs embedded in the market price of electricity. In opening comments on the proposed decision, the investor-owned utilities suggest that to determine the amount of revenue needed to provide the volumetric return established herein to residential and small business customers, they should be allowed or/directed to multiply the allowance revenues by the Commission-approved generation cost allocators that are used to allocate costs to different customer classes.

Because it is possible, and indeed likely during the first Cap-and-Trade compliance period, that the value of allowances will exceed GHG costs, this approach would appear to result in overcompensation to those customers eligible for a volumetric return, as relative to their anticipated Cap-and-Trade costs, which is not an outcome we desire. This outcome is possible because the allocation of allowances to Electric Distribution Utilities, including the investor-owned utilities, was based on projections of anticipated cost burden under the

Cap-and-Trade program adjusted to recognize investment in energy efficiency and early action on renewable resources. However, we agree with the investor-owned utilities in principle that applying the Generation Cost Allocators to estimated Cap-and-Trade costs, instead of allowance revenues, may provide a potentially simplified approach to determining the amount of allowance revenues required to provide the volumetric return to residential and small business customers. A reasonable proxy appears to be the application of each utility's Commission approved generation costs allocator applied to forecasted GHG costs. Although we defer a final finding on this matter to the implementation phase of this proceeding, we believe this conceptual approach has merit that should be further developed and refined.

If, after three application cycles, the Commission finds that forecasting and reconciling GHG costs and revenues becomes more ministerial, the Commission may elect to allow PG&E, SCE and SDG&E to include GHG costs and revenues in rates based on forecasts approved in each utility's ERRRA or other appropriate proceeding, prospectively. PacifiCorp and CalPeco may similarly be authorized to include GHG costs and revenues in rates based upon forecasts approved in their respective Energy Cost Adjustment Clause mechanisms or other appropriate proceeding.

6.1.1.1. Memorandum Accounts

In Sections 5.8.3 and 5.9 above, we authorize the establishment of memorandum accounts to track customer outreach and administrative costs, respectively. The utilities, with the exception of Bear Valley, must file Tier 1 advice letters within 30 days of the issuance of this decision showing establishment of such accounts.

6.2. Finalization of EITE and Small Business GHG Revenue Formulas

We do not have adequate record at this time to fully adopt formulas for returning GHG allowance revenues to EITE and small business customers, including EITE customers with third-party owned CHP. For EITE customers, the Commission's Energy Division, with input from ARB, has developed a preliminary methodology that parallels ARB's allowance allocation methodology for Industrial Covered Entities. In Appendix A to this decision, we set forth, but do not adopt, preliminary formulas and a rationale for those formulas that would be used to determine the amount of GHG allowance revenues to be received by each EITE entity. Similarly, for small business customers, in Appendix B, we set forth, but do not adopt, a preliminary formula that would be used to determine the amount of GHG allowance revenues to be received by each small business customer.

Within 60 days of issuance of this decision, Energy Division staff shall initiate a public workshop process whereby interested parties may provide feedback on the proposed EITE and small business allocation formulas set forth in Appendices A and B.⁹⁸ The workshop process shall also identify required input sources as well as the process and timing of all information and data exchanges that must occur to calculate the revenue return. Furthermore, the workshop process shall explore the appropriate timing of GHG revenue distribution to EITE and small business customers, and, for the EITE return, whether the allowance revenue should be returned as an on-bill credit or an off-bill check. Finally, the workshop shall explore possible alternatives to the

⁹⁸ The assigned Commissioner or ALJs have the authority to modify this date.

requirement to opt-into the Cap-and-Trade program for EITE entities within sectors designated as eligible for Industry Assistance by ARB with emissions less than 25,000 MTCO_{2e} in order to obtain necessary data to calculate a GHG revenue return.

Subsequent to these workshops, Energy Division must prepare and submit in this proceeding a workshop report summarizing the positions of parties and setting forth recommended formulas and recommended timing and mechanics for distribution of GHG revenues to EITE and small business customers. The report must also include all necessary information and data exchange details discussed above. Parties will have an opportunity to comment on the workshop report prior to issuance of a decision adopting finalized formulas. On a prospective basis from the issuance of the decision adopting specific formulas, inputs, and process, minor updates to the adopted formulas may be made by the Energy Division as necessary through the issuance of a resolution with opportunity for stakeholder input and comment.

6.2.1. ARB and Commission Working Agreement

The adopted EITE GHG allowance revenue allocation methodology will require a strong working relationship with ARB in order to facilitate the exchange of data necessary to determine the correct amount of GHG allowance revenues to be credited to each EITE entity. This need arises because the calculations are anticipated to largely depend on information that eligible entities (including eligible entities with emissions less than 25,000 MTCO_{2e} that opt into the Cap-and-Trade program) will be reporting to ARB. Since ARB and the Commission will need to collaborate extensively and have a clear working relationship, we authorize the Commission's Energy and Legal Divisions to enter into an interagency agreement with ARB in order to facilitate the exchange of all

necessary data and information, including any necessary confidentiality agreements to protect market sensitive information.

6.3. Implementation of GHG Revenue Allocation Methodology

In order to fully implement our GHG revenue allocation methodology, the utilities will need to provide us with additional information. As such, we direct PG&E, SCE and SDG&E to jointly file a report in this proceeding, R.11-03-012, within 45 days of the effective date of this decision, addressing how they intend to implement the adopted GHG revenue allocation methodology.⁹⁹ The primary purpose of this report is for the investor-owned utilities to explain how they will apportion allowance revenue for each of the purposes authorized in this decision given the uncertainty surrounding both the total amount of allowance revenue that the utilities will receive and have on hand at any moment and the amount of revenue that will be necessary to compensate EITE, small business, and residential customers and to fund customer education and general administrative costs incurred to implement this decision. The utilities' implementation plans will ultimately be approved through the issuance of a subsequent decision. At a minimum, the report should address:

1. EITE Return: Describe how the utilities will estimate and set aside an appropriate amount of allowance revenue to cover the allocation to EITE customers as defined in this decision, including EITE customers served by CCA or DA providers. The utilities must also set forth a proposed methodology to ensure that EITE customers that are also classified as small business customers do not receive duplicative GHG allowance revenues;

⁹⁹ The formulas for calculating the EITE and small business return may not be fully adopted in advance of the filing of this report. The utilities should address the requested information to the best of their ability at the time of filing; amended filings may be necessary. The assigned Commissioner or ALJs have the authority to modify the date reports are to be filed.

2. Small Business Volumetric Return: Describe the process the utilities will use to identify small business customers that qualify for the allowance revenue return as defined in this decision, recognizing that some small business customers will be served by CCA or DA providers. Also, define the methodology the utilities will employ to determine what magnitude of volumetric return, in dollars per kWh, will be applied to the rates of qualifying small businesses;
3. Residential Volumetric Return: Define the methodology the utilities will employ to determine what magnitude of volumetric return, in dollars per kWh, will be applied to the rates of residential customers to fully offset the GHG costs that will be reflected in residential rates, recognizing that some residential customers are served by CCA or DA providers;
4. Residential Climate Dividend: Describe the methodology the utilities will employ to estimate the amount of allowance revenue that will remain for the non-volumetric return to residential customers (after offsetting GHG costs in residential rates, providing a return to small businesses and EITE customers, and accounting for customer education and overall administrative costs). Describe the methodology the utilities will use to determine the amount of allowance revenue that will be returned to each residential account recognizing that some households may have more than one account owing to, for example, multiple meters on a single residential premises. This methodology can include a buffer, if necessary, to ensure that adequate funds remain to compensate EITE customers. Describe the methodology the utilities will use to address the circumstances where the climate dividend exceeds a customer's monthly bill for multiple months and/or a customer with a climate dividend balance leaves a utility's service territory. Provide an estimate of the per-residential account return for 2013;
5. GHG Costs: Describe the methodology the utilities will employ to calculate realized GHG costs against which to apply GHG allowance revenues.
6. Administrative Costs: Provide an estimate and supporting analysis of the up-front and ongoing administrative costs that

will be incurred in order to implement our adopted GHG revenue allocation methodology (including any billing system upgrades, etc., that may be necessary) for calendar year 2013;

7. CCA and DA Customers: Describe the exact process that will be used to distribute GHG allowance revenue to CCA and DA customers;
8. Describe the methodology the utilities will use to implement the interim cash-out provision for net-metering customers for instances in which residential Cap-and-Trade program bill credits (the climate dividend) would otherwise be stranded if the value exceeds the bills a customer faces during the calendar year in which the customer received the bill credits;
9. Propose a methodology for distributing the residential climate dividend equitably to master-meter customers; and
10. List all necessary balancing accounts and tariff modifications that will be required to track GHG costs and revenues for each customer group eligible to receive GHG allowance revenues.¹⁰⁰

Shortly following issuance of the instant decision, a ruling will issue finalizing the required contents of the utility reports. The assigned Commissioner or ALJs may modify the list above or include additional items in the ruling. In developing the reports, we strongly encourage the utilities to work with stakeholders, particularly CCA and DA representatives, in advance of filing and, to the fullest extent possible, to develop a uniform approach on these various issues. We anticipate that issues concerning the reports can be resolved

¹⁰⁰ Customers eligible to receive GHG allowance revenues will, except in the case of residential customers, be sub-sets of customers that receive service under various tariffs. Said differently, eligible and ineligible customers may currently be served under the same tariff. We expect the appropriate solution may include creating new tariffs otherwise identical to existing tariffs, except that eligible customers will now be segregated from ineligible customers. We will consider other solutions to this practical problem and subsequently adopt the most accurate and efficient reasonable option.

through workshops and comments, and one or more proposed decisions shall issue to approve the implementation plans.

6.4. Implementation of GHG Revenue Allocation Methodology for Small and Multi-Jurisdictional Utilities

6.4.1. PacifiCorp and CalPeco

We are cognizant that, because of the smaller size, unique operating characteristics and limited GHG allowance revenue expected by PacifiCorp and CalPeco, administrative costs to implement our adopted GHG revenue allocation methodology exactly as prescribed for PG&E, SCE, and SDG&E may be excessive. Therefore, we will allow PacifiCorp and CalPeco some added flexibility in applying our adopted GHG allowance revenue allocation methodology. We direct PacifiCorp and CalPeco to each file in this proceeding a report describing their plans for implementing the requirements to distribute allowance revenue to their EITE, small business and residential customers¹⁰¹ no later than 30 days after the joint implementation report is filed by PG&E, SCE, and SDG&E. This report should address all of the topics set forth in Section 6.3, above. To the extent that PacifiCorp or CalPeco wish to modify the methodology adopted for PG&E, SCE, and SDG&E to keep their implementation and ongoing administrative costs relatively small in proportion to the allowance revenues they receive, PacifiCorp and CalPeco must describe the modifications they plan to make and provide justification for those modifications in their filings. Similar to the process adopted for PG&E, SCE, and SDG&E, we anticipate that issues

¹⁰¹ As noted earlier, the assigned Commissioner or assigned ALJs may modify the date and contents of the reports, which will be finalized through issuance of a ruling.

concerning the reports can be resolved through workshops and comments and one or more proposed decisions.

6.4.2. Bear Valley

Because Bear Valley will receive a de minimis amount of allowance revenue and we authorize a volumetric return of all of Bear Valley's GHG allowance revenues, establishment of separate balancing accounts should not be necessary. Furthermore, implementation of Bear Valley's allowance revenue allocation approach should be straightforward and should not require any further action by this Commission. Therefore, Bear Valley is exempt from any filings that we require of the other utilities in this decision.

6.5. Implementation of Customer Outreach and Education

We will need to review the utilities' customer outreach and education plans for 2013 in order to ensure that the plans adhere to the guidelines adopted in this decision. Therefore, no later than 30 days after each utility files its implementation plans pursuant to Sections 6.3 and 6.4.1, PG&E, SCE, SDG&E, PacifiCorp and CalPeco must file Tier 2 advice letters setting forth the scope and estimated timing of their proposed customer outreach activities for 2013, consistent with the requirements set forth in Section 5.8.1. The advice letter should also clearly describe, including examples if necessary, the presentation of the separate line-item on bills for the return of the climate dividend to residential customers. The utilities should solicit input from CCA and DA providers prior to the filing of advice letters.

To address customer outreach and education in 2014 and beyond, the utilities must file applications by September 1, 2013 setting forth their proposed customer outreach plans for 2014 and 2015, incorporating the results of the consultant's report and including estimated yearly budgets. By July 1, 2015, the

utilities must file a second application addressing customer outreach and education activities for 2016-2020, including estimated yearly budgets.

7. Outstanding Motions

Numerous parties have filed motions in Track 1 Phase 1 of this proceeding requesting party status or asking for resolution of specific issues. To our knowledge, we have addressed all outstanding motions either via electronic or written ruling; however, outstanding motions in Track 1 Phase 1 of this proceeding are hereby denied.

8. Categorization and Need for Hearing

In the September 1, 2011 Scoping Memo, the Commission confirmed the categorization of this proceeding as ratesetting and set forth a process by which parties could request hearings. No requests for hearings were received, and all issues in Phase 1 of Track 1 of this proceeding were sufficiently addressed through proposals, workshops and comments. Therefore, we confirm our initial determination that evidentiary hearings are not needed in Phase 1 of Track 1 of this proceeding.

9. Comments on Proposed Decision

The proposed decision of the assigned ALJs for this proceeding was mailed to parties in accordance with Pub. Util. Code § 311, and comments were allowed in accordance with Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 6, 2012, and reply comments were filed on December 11, 2012. We have weighed parties' comments, and in the situations deemed appropriate we have modified our proposed decision. We have made many non-substantive revisions to correct minor errors and improve clarity.

We make the following substantive revisions and clarifications to the proposed decision:

1. We change our discussion in Section 5.3.1.3 pertaining to EITE customers that have emissions levels less than 25,000 MTCO₂e and that operate in sectors that qualify for Industry Assistance to state that such customers must voluntarily opt into the Cap-and-Trade program in order to be eligible to receive allowance revenue for the indirect emission costs associated with their electricity purchases unless another method can be developed to accurately obtain the necessary information to calculate revenue returns in the implementation phase of this proceeding.
2. In Section 5.4.1, we state that should the Commission expand the definition of EITE entities to include sectors or entities that are not covered under ARB's Industry Assistance methodology, allocation formulas will need to be developed to return GHG allowance revenues to these customers. We find that these formulas should rely on methodologies that are similar to those ultimately adopted to return GHG revenues to EITE entities that qualify for Industry Assistance, to the extent practical.
3. In Section 5.4.4.1, we clarify our intent that all EITE entities that purchase electricity from third-party owned CHP receive equal treatment under the EITE GHG revenue allocation formulas ultimately adopted in this proceeding.
4. In Section 5.4.1.1.1, we clarify that GHG allowance revenues must be applied against the delivery component of an EITE customer's charges, if an on-bill delivery method is ultimately adopted in the implementation phase of this proceeding, to ensure that all EITE customers receive GHG allowance revenue whether they are interconnected at the distribution or transmission level.
5. In Section 5.4.3.2.3, we find that if the climate dividend exceeds a customer's monthly bill, any remaining climate dividend must be applied to the subsequent month's bill until the climate dividend is exhausted. We acknowledge

that certain circumstances may prohibit this approach and we will address such circumstances in the implementation phase of this proceeding.

6. In Section 5.4.4, we clarify our intent that residential master-meter customers receive their proportional share of the climate dividend.
7. In Section 5.6, we find that, in order to ensure competitive neutrality, GHG compliance costs must be included in the generation component of rates and allocated to CCA and DA customers in the same manner that other generation costs are allocated to bundled customers.
8. In Section 5.8.1, we find that customer outreach activities must ensure that hard-to-reach customers receive adequate information and education. We remove the outright prohibition on the use of utility logos and find that all references in marketing materials pertaining to GHG allowance revenue returns must be attributed to the State of California or the State of California's Cap-and-Trade program. We find that any communications from investor-owned utilities to CCA and DA customers pertaining to the distribution of GHG allowance revenues or the Cap-and-Trade program must include the logos of both the investor-owned utility and the CCA or DA provider. Furthermore, we find that CCA and DA providers must have the opportunity to review the utilities' 2013 customer outreach plans prior to the filing of plans for approval. Finally, we clarify that any communications from the Commission to electricity customers must be absent any utility logo.
9. In Section 5.8.2, we find that the utilities must consult with DA and CCA providers in the engagement of the marketing and public relations firm. Furthermore, the marketing and public relations firm must evaluate the feasibility and potential advantages and disadvantages of the use of a third-party administrator for customer outreach and education activities.

10. In Section 6.1, we change our discussion to find that the utilities must defer including in rates both the GHG costs and revenues, including interest, for all retail customers. We adopt a definition for GHG costs and state that costs shall be deferred based upon 2013 GHG cost forecasts approved in each utility's ERRR or Energy Cost Adjustment Clause proceedings. Finally, we state that the deferral of GHG costs in rates does not create a competitive disadvantage between investor-owned utilities and CCA and DA providers but find that any communication of existing investor-owned utility rates to customers shared by the investor-owned utility and CCA or DA providers must accurately disclose their respective deferred GHG costs.
11. In Section 6.1.1, we insert a discussion on a potential methodology to calculate actual GHG costs incurred, which would rely upon the application of Commission-approved generation costs allocators against forecasted GHG costs; however, we defer a final finding on this matter to the phase of the proceeding addressing implementation issues.
12. In Section 6.4.1, we change the date that PacifiCorp and CalPeco must submit their implementation reports to 30 days after the joint implementation report of PG&E, SCE, and SDG&E is filed.
13. In Section 6.5, we change the date that the utilities must file the Tier 2 Advice Letter addressing 2013 customer education and outreach activities to 30 days after each utility files its implementation plans. We further find that the advice letter must clearly describe the presentation of the separate line-item on bills for the return of the climate dividend to residential customers.

Finally, in response to opening comments on the proposed decision filed by the Large Users pertaining to our discussion on the "public asset" nature of the atmospheric carbon sink, we find the Large User's concerns to be overstated. As noted by the Large Users, we rely on this policy objective as one of many in

adopting our GHG allowance revenue methodology, and our reliance on this objective weighs most heavily on a refutation of the argument that equity requires that those who pollute the most should be allocated revenues on the basis of their emissions.

10. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Melissa K. Semcer and Jessica T. Hecht are the assigned ALJs in this proceeding.

Findings of Fact

1. The Global Warming Solutions Act of 2006, AB 32, caps California's GHG emissions at 1990 levels, with this level to be reached by 2020.
2. California's Cap-and-Trade program creates an economy-wide cap on major sources of GHG emissions, including refineries, power plants, industrial facilities and transportation fuels.
3. ARB adopted the final Cap-and-Trade regulation to implement AB 32 in December 2011, and the regulation became effective on January 1, 2012. On June 29, 2011, ARB Chairwoman Mary Nichols announced a one-year delay in the enforcement of the Cap-and-Trade program, until 2013.
4. ARB has three main responsibilities under the Cap-and-Trade program: (1) cap GHG emissions by issuing a limited number of tradable permits (allowances) equal to the emissions cap; (2) reduce the cap over time to reach 1990 level emissions by 2020; and (3) enforce the cap by requiring each entity that operates under the cap to turn in one allowance for every metric ton of carbon dioxide equivalent gas that it emits.
5. During 2013 and 2014, the cap will apply to approximately 37% of California's economy-wide emissions, consisting of electricity generation and large industrial sources and processes with annual GHG emissions at or above

25,000 MTCO₂e as well as carbon dioxide suppliers. The Cap-and-Trade program will expand in 2015 to include approximately 85% of emissions, including emissions from fuels used for transportation, as well as emissions from fuel combusted by all commercial, residential and small industrial sources that have emissions below 25,000 MTCO₂e.

6. The Cap-and-Trade program regulates emissions from both imported electricity and electricity generated within California. The first party that places electric power onto the California grid is responsible for emissions associated with that power under the Cap-and-Trade regulation.

7. For in-state generation, the covered entity for the purposes of the cap is the source of generation. In-state generators are only covered if their emissions exceed 25,000 MTCO₂e, with their compliance obligation equal to the facility's total emissions. For imported electricity, the covered entity is the first entity to deliver electricity onto the California grid, and emissions can be either specified (meaning that emissions from the generating facility are known) or unspecified.

8. The value of GHG allowances derives from the economy-wide, annually decreasing cap on GHG emissions, along with the requirement that each entity covered by the Cap-and-Trade regime surrender compliance instruments – GHG allowances and a limited number of GHG offsets – equal to their emissions for the year.

9. The total number of allowances ARB issues in any given year is equal to the state-wide GHG cap for that year. Individual covered entities do not have specific emission limits.

10. Because allowances are tradable, the cap effectively creates a market for GHG allowances, through which the market price of allowances is expected to closely reflect the marginal cost of GHG abatement.

11. ARB has taken an allowance allocation approach that combines auction-based allocation with a limited free (direct) allocation to individual entities for the purpose of protecting electricity customers and advancing other AB 32 objectives, providing transition assistance to certain industries, and limiting emissions leakage.

12. Under the Cap-and-Trade regulation, ARB granted to electric distribution utilities a direct allocation of allowances for the purpose of protecting electricity customers and advancing AB 32 objectives.

13. Investor-owned utilities receive an allowance allocation on behalf of all customers of the distribution utility, including DA and CCA customers.

14. The investor-owned utilities subject to the Commission's jurisdiction must consign all of their allowances to auction, with the proceeds to be used for the benefit of all ratepayers, including DA and CCA ratepayers, consistent with the goals of AB 32.

15. The allowance allocation to individual utilities in any given year is equal to the total 97.7 MTCO₂e allocated to electrical distribution utilities in 2013 (inclusive of investor-owned and publicly-owned utilities) multiplied by a cap adjustment factor, which decreases annually through the 2013-2020 period, and a percentage allocation factor based on the utility's proportion of the projected emission in the electricity sector.

16. The schedule of allowance allocations to the electricity sector as a whole was calculated by ARB using 2008 historical emissions for the sector, including emissions associated with purchases from combined heat and power facilities, multiplied by 90%. The per year allocation, beginning in 2012, was then calculated by linearly declining this amount such that it is reduced to 85% of its initial 2012 level by 2020.

17. To calculate the allocation to each of the electric distribution utilities within the electricity sector, ARB calculated each utilities' anticipated share of the overall cost burden under Cap-and-Trade, adjusted to recognize cumulative energy efficiency, and early investment in renewables.

18. Based on the lowest possible sale price for an allowance, which is ARB's auction floor price, and a reasonable upper bound price, the trigger price of ARB's Price Containment Reserve, the value of allowances allocated to the investor-owned utilities will be worth between approximately \$650 million and \$2.6 billion in 2013. Using these same parameters, the estimated value of allowances over the course of the Cap-and-Trade program (2013-2020) is between \$5.7 and \$22.6 billion for PG&E, SCE and SDG&E, combined.

19. Introducing an environmental regulation in one jurisdiction can cause production costs and prices in that jurisdiction to increase relative to costs in jurisdictions that do not introduce comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction towards goods produced elsewhere. As a result, a reduction in emissions in the implementing jurisdiction is offset by increased production and emissions elsewhere. This offsetting increase in emissions is called emissions leakage.

20. Emissions intensity is an indicator of the impact that carbon pricing will have on an industrial sector's economic output. Those with higher emissions per unit of output are considered to be more emissions intensive.

21. Trade exposure is a measure of the degree of competition a sector faces from entities operating outside of the Cap-and-Trade program, and the associated ability of consumers to shift demand to those providers that do not bear any carbon costs.

22. Without assistance, industries that are both highly emissions intensive and trade exposed have the potential to experience leakage due to the Cap-and-Trade program. Under the Cap-and-Trade regulation, such entities are referred to as Industrial Covered Entities that qualify for Industry Assistance.

23. Through the Cap-and-Trade regulation, ARB establishes methodologies for allocating allowances to Industrial Covered Entities That qualify for Industry Assistance. These methodologies are based on various factors, including industrial classification and an assessment of leakage risk (low, medium, or high). The amount of allowances allocated freely to Industrial Covered Entities eligible for Industry Assistance steps down at different rates for different entities, depending upon their leakage risk, between 2013 and 2020.

24. Existing state statutes and regulations limit the ways in which the Commission may direct investor-owned utilities to use GHG allowance revenues.

25. Sections 95800-96023 of Title 17 of the California Code of Regulations (the Cap-and-Trade regulation) codify the rules that govern the Cap-and-Trade program in California. Sections 95892(d)(2-5) adopt limitations on the use of GHG allowance auction revenue for the investor-owned utilities subject to the Commission's jurisdiction.

26. SB 695 places restrictions on the Commission's ability to increase PG&E, SCE and SDG&E's lower-tier (Tiers 1 and 2) residential rates (CARE and non-CARE) throughout the duration of the Cap-and-Trade program. Similar restrictions do not apply to PacifiCorp, CalPeco and Bear Valley.

27. On June 27, 2012, Governor Brown signed SB 1018, which, among other actions, added § 748.5 to the Public Utilities Code setting forth specific

parameters on the use of GHG allowance revenues by the electric utilities regulated by this Commission.

28. Section 748.5 sets a basic framework for GHG allowance revenue distribution but it leaves many aspects of the distribution methodology to the Commission's discretion, and there are several sources of ambiguity in the statute. Terms requiring interpretation include "small business" and "emissions-intensive and trade-exposed." Implementation details left to the Commission's discretion include determining the methodology for providing a direct return to "emissions-intensive and trade-exposed," "small business," and residential retail customers, setting forth the scope and budget for customer education activities, and selecting the percentage of revenues that will be allocated toward clean energy and energy efficiency projects, not to exceed 15%.

29. D.08-10-037, the Final Opinion on Greenhouse Gas Regulatory Strategies, in Phase 2 of R.06-04-009, set forth the Commission's direction on the use of GHG allowances, including a provision that all GHG allowance auction revenues should be used for purposes related to AB 32. Such uses should be limited to direct steps aimed at reducing GHG emissions and also utility bill relief to the extent that the GHG program leads to increased utility costs and wholesale price increases. Furthermore, any mechanism implemented to provide bill relief should be designed so as not to dampen the price signal resulting from the Cap-and-Trade program.

30. In most cases, increased costs of electricity production as a result of the Cap-and-Trade program will ultimately be passed through to the end user of electricity – the retail electricity ratepayer– resulting in higher retail electricity rates.

31. Based on the E3 model, between 2013 and 2020 system average rates will be approximately 2% higher than they would be absent the Cap-and-Trade program, assuming allowance prices stay at ARB's price floor, and approximately 8% to 9% higher than they would be absent the Cap-and-Trade program if allowance prices reach the ARB Reserve price.

32. If retail rates do not reflect GHG costs, CHP could be placed at an economic disadvantage compared to separate heat and power, even if it is highly efficient and net-GHG-reducing.

33. Industry Assistance status and ownership structure of a CHP unit affect the amount of free allowances distributed to the CHP unit's host customer.

34. An efficient allocation of society's scarce resources requires that the price of goods and services reflect the full, social costs of their production. In order to preserve the incentives the Cap-and-Trade program is intended to provide, the cost of carbon should generally be reflected in the price of electricity so that these costs can in turn, be appropriately reflected in the price of goods and services that rely on electricity. Absent this, electricity consumption and consumption of goods and services that use electricity will be higher than the socially optimal level.

35. In certain cases, where statute or other requirements prevent the Commission from preserving the carbon price signal, it is appropriate to return GHG revenues in a manner that does not strictly adhere to the objective of maintaining the carbon price signal.

36. Inclusion of a carbon price for both generators and retail customers creates an incentive for all market actors to find the most efficient ways to reduce GHG emissions.

37. The provision of GHG allowance revenue in proportion to costs borne under the Cap-and-Trade program would disproportionately reward high consumption energy users.

38. Administrative simplicity and understandability of an adopted GHG revenue allocation methodology must be weighed against achievement of higher-priority objectives.

39. High priority policy objectives in the context of this decision are preserving the carbon price signal, preventing economic leakage, reducing adverse impacts on low income households, and maintaining competitive neutrality.

40. Medium priority policy objectives in the context of this decision are distributing revenues equitably recognizing the public asset nature of the atmospheric carbon sink, and achieving administrative simplicity.

41. Consistent with SB 1018, customer education and understanding is an important component of the adopted GHG allowance revenue allocation methodology.

42. The plain language of § 748.5(a), by designating specific customer classes (namely residential, small business, and emissions-intensive and trade exposed) as the recipients of directly credited GHG allowance revenues, limits the Commission's authority to grant direct relief to customer groups outside those classifications.

43. The term "small business" in § 748.5(a) is ambiguous; statutory history yields no information to relieve this ambiguity.

44. The SBA and DGS definition of "small business" would require the utility to verify eligibility or the small business to provide documentation to show eligibility. Requiring a small business to provide documentation, and thus opt-in

to receive GHG allowance revenue, could result in small businesses foregoing the process, which would undermine the direction of § 748.5(a) to return GHG revenues directly to small business ratepayers.

45. The Commission has historically relied upon a usage-based 20 kW demarcation point to define small businesses with varying qualifiers, depending upon the program.

46. Requiring that a small business not exceed 20 kW demand in more than three months within the previous twelve month period provides operational flexibility and does not penalize a business for demand that exceeds 20 kW from time to time.

47. For the purposes of § 748.5(a), a small business is one with an electric demand that does not exceed 20 kW in more than three months within the previous twelve-month period.

48. The term “business” can be interpreted to have a broader meaning than the term “commercial,” as that term is used by the utilities in setting commercial electricity rate tariffs.

49. Providing GHG revenues solely to small business customers on commercial tariffs would result in many classes of non-residential customers that could reasonably be considered to be a business, including agricultural customers, receiving no GHG revenue value.

50. To avoid an outcome where some small business customers receive GHG allowance revenues, while others do not, any non-residential customer on a General Service or Agricultural tariff with demand not exceeding 20 kW in more than three months in the previous 12-month period is considered to be a small business.

51. The term “emissions-intensive and trade-exposed” in § 748.5(a) is ambiguous; statutory history yields no information to relieve this ambiguity.

52. ARB has applied the term “emissions-intensive and trade-exposed” to describe entities designated under the Cap-and-Trade regulation as qualifying for Industry Assistance.

53. The use of the general terms “emissions-intensive and trade-exposed,” rather than the more formal terminology adopted in the Cap-and-Trade regulation can be construed to mean that § 748.5(a) intended to offer broader protection than solely to those entities qualifying for Industry Assistance.

54. ARB, in designating certain industry classes as qualifying to receive Industry Assistance under its GHG allowance allocation methodology, did not opt to provide relief to those entities for the increased costs due to the Cap-and-Trade program and associated with their indirect emissions from purchased electricity

55. The risk of emissions leakage results not only from the direct compliance obligations entities eligible for Industry Assistance may face under the Cap-and-Trade program but also indirect costs embedded in the price of electricity they use, to the degree retail rates reflect a carbon price.

56. The indirect emissions associated with the purchase of electricity will result in even higher emissions cost exposure for entities eligible for Industry Assistance, and therefore higher costs under the Cap-and-Trade program, thus further aggravating economic and emissions leakage risk. Such leakage would harm California’s economy while doing nothing to reduce GHG emissions.

57. Entities that are part of industries that qualify to receive Industry Assistance, but with emissions levels less than 25,000 MTCO_{2e}, also face similar

leakage risk as their covered peers within a given industrial sector, although they do not have a compliance obligation under the Cap-and-Trade regime.

58. ARB must have certain information, for example, production data, associated with an entity eligible for Industry Assistance in order to provide the Commission with the necessary data to calculate the amount of GHG allowances to distribute to that entity. To the degree the approach taken to address indirect emissions costs will mirror that used by ARB for direct emissions costs, similar data will be required to provide compensation to address these indirect costs. Therefore, entities with emissions levels less than 25,000 MTCO₂e that operate in sectors eligible for Industry Assistance must voluntarily opt-into the Cap-and-Trade program, unless another suitable method can be found to accurately obtain the necessary information to calculate revenue returns for these customers.

59. There may be some entities or sectors that are not subject to the cap that could pose a leakage risk as a result of their indirect emissions. It is possible that electricity intensity could be correlated with emissions intensity (although not always) and leakage risk due to trade exposure could become an issue for these entities due to the embedded cost of carbon in electricity prices.

60. There is not adequate record at this time to extend the EITE designation to entities or sectors beyond those that qualify for Industry Assistance under the Cap-and-Trade regulation. A prompt additional process will be needed to make such a determination.

61. Section 748.5(a) specifically ties together the terms “emissions intensive” and “trade exposed” by the word “and.” This indicates that, in order to be eligible to receive GHG allowance revenue under the statute, entities have to be both emissions intensive and trade exposed; designation as solely “emissions

intensive” or “trade exposed” does not result in an entity being classified as EITE.

62. The mere presence of competition between business entities within California and outside of California does not necessarily qualify an entity as trade-exposed. The mere presence of indirect emissions attributable to a business entity from its electric purchases does not necessarily result in that entity being considered to be emissions-intensive.

63. For the purposes of § 748.5(a), an “emissions-intensive and trade-exposed” entity is one that is part of an industry that qualifies for Industry Assistance under the Cap-and-Trade regulation, regardless of the amount of emissions produced.

64. It is possible that an entity classified as EITE, as defined in this decision, may also qualify as a small business, as defined in this decision, which could result in a single entity receiving duplicative GHG allowance revenue.

65. Section 748.5(b) does not set forth metrics for measuring achievement of “maximum feasible public awareness.” The term “maximum public awareness” is a flexible standard tempered by the term “feasible.”

66. Given that SB 1018 was passed in late June of 2013, it will not be feasible for the utilities to adopt and implement a comprehensive customer education program by January 1, 2013. Customer outreach and education can be expanded in 2014 and beyond.

67. The Commission’s long-held reasonableness approach of evaluating costs as compared to achievement of customer outreach and education goals is consistent with the standard established in § 748.5(b).

68. There is no direct linkage between application of GHG allowance revenue toward energy efficiency and clean energy programs and ability to measure “maximum feasible public awareness.”

69. The plain language of § 748.5(b) is clear. The utilities may recover the cost of customer outreach programs in rates, subject to the procedural requirements set forth in § 454. The language does not directly address whether GHG allowance revenues can be used to pay customer outreach costs.

70. Nothing in § 454 precludes the Commission from considering issues of equity or undertaking a cost/benefit analysis in allocating revenue requirements differently to different ratepayer groups.

71. It is appropriate to allocate customer outreach costs to those customers that will be the beneficiaries of the direct crediting of GHG allowance revenue.

72. Requiring GHG revenues to flow back to residential, small business, and EITE ratepayers, adding customer outreach costs to rates, and then requiring those same customer groups to pay the outreach costs is unnecessarily complex.

73. Applying GHG revenue to fund customer outreach costs results in the same outcome as requiring revenues to flow back to customers while at the same time charging those customers for customer outreach costs in rates.

74. Achievement of maximum feasible public awareness extends beyond outreach to residential ratepayers.

75. Costs associated with customer outreach and education under § 748.5(b) are correctly funded by GHG allowance revenues.

76. GHG revenues allocated toward customer outreach and education or administrative costs will reduce the amount of GHG revenues ultimately received by residential customers.

77. Section 748.5(c) imposes a cap of 15%, but not a minimum or specific requirement, on the amount of GHG allowance revenues that may be allocated toward clean energy and energy efficiency programs.

78. The meaning of the term “established pursuant to statute” in § 748.5(c) is ambiguous; statutory history yields no information on which to relieve the ambiguity.

79. The Commission has jurisdiction to establish specific clean energy and energy efficiency programs and projects. Section 748.5(c) does not alter the Commission’s statutory authority.

80. A program or project that falls under the purview of a statutorily created program over which the Commission has jurisdiction, such as energy efficiency or the Renewables Portfolio Standard, is considered to be “established pursuant to statute” for the purposes of § 748.5(c).

81. The plain language of § 748.5(c) states that a clean energy or energy efficiency project must not otherwise be funded in order to receive funding through GHG allowance revenue. It is unclear whether the statute prohibits the Commission from allocating GHG revenues toward existing clean energy or energy efficiency projects or programs.

82. Shifting the funding for a program that was previously paid for by utility ratepayers would save money on energy efficiency or clean energy projects, but the shift would not increase the availability of such projects and would violate statute.

83. An existing project may be funded with GHG allowance revenue only if the general funding previously supporting the project is directed to another project within the same program.

84. ARB established leakage risk factors for each covered sector eligible to receive Industry Assistance (high, medium, or low) and employed a variety of benchmarking methodologies based upon characteristics of the sector as a whole (i.e. product-based or energy-based allocation methodologies) to determine the appropriate amount of Cap-and-Trade program allowances to allocate to entities qualifying for Industry Assistance.

85. The distribution of GHG allowance revenues to EITE entities to cover indirect emissions costs in a parallel manner, to the extent practical, to the allocation of allowances for direct emissions under ARB's Industry Assistance program ensures that EITE sectors with higher leakage risk receive proportionally greater transition assistance for increased electricity costs while also ensuring that the carbon price signal of electricity is not muted for any individual entity. This methodology also ensures that EITE entities are treated similarly for both their direct and indirect emissions and will help to streamline the transition should the ARB modify the Cap-and-Trade regulation to include the indirect emissions associated with electricity purchases by EITE entities in their formulas for allowance distribution to entities qualifying for Industry Assistance.

86. Further record is needed to finalize EITE allocation formulas. A preliminary methodology is set forth, but not adopted in Appendix A to this decision; an implementation process will be necessary. Further record is also needed to finalize the form, whether on-bill or off-bill, of compensation to EITE entities.

87. Should the Commission expand the definition of EITE entities to include sectors or industries that are not covered under ARB's Industry Assistance

allocation methodology, allocation formulas will need to be developed to return GHG allowance revenues to provide compensation for indirect emissions.

88. ARB's allowance allocation approach appears to result in disparate levels of assistance across refineries even when those refineries are substantially similar in their operations. A refinery that owns its CHP facility is eligible to receive assistance that more closely reflects its emission costs than a refinery that does not. The issue of disparate treatment extends beyond the refinery sector.

89. It is important to ensure that all EITE entities that purchase electricity from third-party owned CHP receive equal treatment under the EITE GHG revenue allocation formulas ultimately adopted in this proceeding.

90. Further record is needed to calculate the appropriate amount of GHG allowance revenue necessary to cover the costs faced by refineries and other EITE entities purchasing electricity from third-party-owned CHP providers. A preliminary methodology is set forth, but not adopted, in Appendix A to this decision; an implementation process will be necessary.

91. Further record is needed to determine the appropriate timing of GHG revenue distribution to EITE customers. In order to better align the amount of compensation provide to EITE entities with actual revenues generated from the sale of allowances, it may be preferable to provide compensation to EITE customers after a given Cap-and-Trade budget year has passed.

92. In order to better align the amount of compensation provided with actual GHG revenues generated from the sale of emissions allowances, providing compensation to EITE customers after a given Cap-and-Trade program budget year has passed is preferable inasmuch as compensation is based on actual market prices, rather than projections.

93. If an on-bill credit is adopted as the distribution methodology for EITE customers, the revenues must be applied to the delivery component of an EITE customer's charges to ensure that all customers within a utility's service territory, irrespective of whether they are a bundled, DA, or CCA customer, are treated equally.

94. The presence of a carbon price in electricity rates, and the reflection of that cost in the price of goods and services, provides a critical incentive for small businesses to shift toward economic activities that result in fewer GHG emissions.

95. Aside from the volumetric return of GHG revenues in proportion to Cap-and-Trade program costs incurred, parties provided few alternate GHG allowance revenue distribution methodology proposals for small business customers.

96. The provision of GHG allowance revenue to small business customers in a manner that mirrors, to the extent possible, the transition assistance methodology adopted for EITE customers ensures that small business customers receive appropriate transition assistance.

97. The adopted approach to compensating most EITE facilities, modeled after ARB's methodology to allocate allowances to Industrial Covered Entities, takes into account each industrial facility's product output and a measure of the facility's emissions intensity and preserves the carbon price signal. It is impracticable to replicate and implement such a detailed methodology for each small business in California.

98. Application of the EITE low-leakage risk Industry Assistance Factor results in an appropriate and administratively simple method of providing transition assistance to small business customers. The low-leakage Industry Assistance

Factor is 100% for the first compliance period, 50% for the second compliance period, and 30% for the third compliance period.

99. Further record is needed to finalize the formula and timing of GHG revenue allocation to small business customers. A preliminary formula is set forth, but not adopted, in Appendix B to this decision; an implementation process will be necessary.

100. The volumetric distribution of GHG allowance revenues to small business customers will largely mute the carbon price signal in small business rates during the first compliance period of 2013-2014; however, in the second compliance period small businesses will see more than half of the carbon price signal in their rates, and in the third program period small businesses will experience substantially all of the carbon price signal in electricity rates.

101. The return of GHG allowance revenues to small business customers via an on-bill credit against their electricity purchases denoted as a separate line-item on bills will increase transparency and facilitate customer understanding and awareness of GHG allowance revenue allocations.

102. AB 1X effectively froze PG&E, SCE and SDG&E's residential Tier 1 and 2 rates from 2001 to 2009. Any new expenses incurred during that time (and assigned to the residential customer class) were recovered entirely in upper-tier residential rates resulting in significant increases in upper tier rates.

103. SB 695 has permitted modest increases in non-CARE Tier 1 and 3 rates since 2009, but no increases in CARE Tier 1 and 2 rates. The small increases in Tier 1 and 2 rates permitted by SB 695 have not narrowed the large gap between lower-tier and upper-tier residential rates.

104. Limitations on the Commission's ability to assign additional costs to PG&E, SCE, and SDG&E's Tiers 1 and 2 rates effectively eliminates the presence

of any Cap-and-Trade program price signal in those rates. Residential customers on lower-tier rates, which represent the vast majority of kWh consumed, will be effectively blind to any carbon price signal and will have no incentive to alter electricity consumption. Customers on upper-tier rates will see a disproportionately strong carbon price signal.

105. Absent a volumetric return of GHG allowance revenues, upper-tier rates would have to increase disproportionately to absorb the GHG costs associated with lower-tier consumption.

106. Neutralizing only the GHG costs in upper-tier residential rates associated with electricity consumption in lower-tier residential rates (thus maintaining GHG costs in upper-tier residential rates associated with electricity demand in the upper tiers) will maintain an inequity between lower-tier and upper-tier rates because lower-tier residential customers will still see no carbon price signal in their rates.

107. Future changes to the current residential tiered-rate structure that result in the reduction or elimination of the existing differences in cost burden between lower-tier and upper-tier residential rates would appear to eliminate the need to offset GHG costs in residential rates.

108. TOU rates are not subject to the same cost burden responsibility differences as tiered rates, where customers on upper-tier rates must bear the costs resulting from the activities of other customers taking service on lower-tier rates. Participation in non-tiered TOU rates is not mandatory.

109. Requiring residential TOU customers to bear GHG costs when customers on tiered rates do not could result in the unintended consequence of deterring customers from adopting TOU rates despite their possible advantages.

110. GHG costs in residential rates must be neutralized at the time such costs are incurred (on a monthly basis) in order to prevent upper-tier residential customers from seeing a carbon price signal in their rates.

111. Highlighting the GHG cost neutralization in rates as a separate line-item on bills may cause confusion among residential customers.

112. GHG revenues must be returned via a delivery rate component that all residential customers pay to ensure that DA and CCA customer receive their proportional share of GHG revenues for the GHG cost offset in residential rates.

113. Residential customers will ultimately bear the increased costs of goods and services in the economy, inclusive of increased electricity costs as a result of the Cap-and-Trade program.

114. Provision of the remaining GHG revenues to residential customers will largely preserve the overall demand for goods and services in the economy. To the extent that residential consumers receive the value of the GHG allowance revenues and subsequently spend these revenues, the net costs of the Cap-and-Trade program are substantially reduced. Total spending in the economy will be largely maintained but will be influenced by pricing that more appropriately reflects the real costs of spending decisions on the environment through the inclusion of a carbon price signal.

115. The non-energy expenses of low-income households will increase as a result of the Cap-and-Trade program due to the increased costs of goods and services inclusive of increased electricity costs. The impact of these price increases will likely be proportionally greater on lower-income households because low-income households tend to spend a greater proportion of their incomes on basic goods and services.

116. There are many differences among residential customer account profiles, including size of household, location (climate), and electricity consumption. As a result of GHG cost neutralization in residential rates, differences among residential customer electricity bills arising from location (climate) are neutralized.

117. A non-volumetric return (climate dividend) of remaining GHG revenues to residential customers on an equal per-residential account basis provides a greater return as a share of income to lower-income households. This is the most equitable method of distributing remaining GHG revenues to residential customers given the neutralization of GHG costs in residential customers' rates.

118. The administrative cost and burden associated with implementation of an off-bill residential rebate is significant and, at this time, outweighs the benefits of an off-bill rebate. Administrative costs associated with an off-bill rebate could reduce the amount of the climate dividend.

119. All residential customers are entitled to their proportional share of GHG allowance revenues. Any process that diminishes the ability of some residential customers to receive that revenue (for example, through loss of a rebate check,) will result in unequal treatment of such customers.

120. Applying the climate dividend directly to residential customers' bills as an on-bill return will largely ensure that all residential ratepayers receive their portion of GHG allowance revenues.

121. An on-bill return of GHG allowance revenues to electricity customers will result in a decrease in electricity bills; however, that decrease will free up money for other purposes that customers would otherwise use to pay their electricity bills.

122. Return of the climate dividend to residential customers via an on-bill credit against their electricity purchases denoted as a separate line-item on bills will increase transparency and facilitate customer understanding and awareness of GHG allowance revenue allocations.

123. The provision of an on-bill credit to all residential customers taking distribution service from an investor-owned utility will ensure equitable treatment of bundled, DA and CCA customers.

124. The frequency of the distribution of the climate dividend to residential ratepayers will have an impact on customer understanding of the Cap-and-Trade program. A semi-annual return of remaining GHG allowance revenues to residential customers reflects the best balance of providing a meaningful return, regardless of allowance price, while not unduly burdening residential customers with prolonged exposure to the higher costs of goods and services.

125. Some residential customers may have more than one residential account per household.

126. The climate dividend may exceed a customers' monthly bill. Any remaining climate dividend must be applied to the subsequent month's bill until the climate dividend is exhausted, unless circumstances prohibit this distribution methodology. Further record is needed to determine a method to address such circumstances, for example if the climate dividend exceeds a customer's bill for a 6-month period and/or a customer leaves a utility's service territory with a climate dividend balance.

127. Customers taking service via a master-meter configuration will be treated equally to all other residential customers in regards to the neutralization of GHG costs in residential rates. This will also be the case for master-meter customers that qualify as small businesses.

128. Residential master-meter customers must receive their proportional share of the climate dividend.

129. Providing the climate dividend to master-metered customers poses certain challenges as these customers, by definition, do not have their own independent utility accounts against which to apply the climate dividend.

130. Residential customers participating in net-energy metering may not have any (or may have a minimal) balance owed to the utility against which to apply the climate dividend. In D.11-06-016, we adopted a methodology whereby net-energy metering customers may receive a cash payment from their utility when a surplus amount of electricity has been generated over a twelve-month true-up period.

131. PacifiCorp, Bear Valley, and CalPeco (the small and multi-jurisdictional utilities) are differently situated than PG&E, SCE, and SDG&E. Significant differences from the larger utilities include not only size but also customer mix (few if any industrial customers, and a higher proportion of part-time residential customers) and customer location (in relatively small and often mountainous areas). In addition, these utilities have fewer customers over which they may spread any administrative or implementation costs of new programs adopted in this proceeding.

132. PacifiCorp and CalPeco expect to receive a significant amount of annual GHG revenue, around \$2 million each.

133. Small and multi-jurisdictional utilities are not subject to the same statutory restrictions imposed by SB 695 on residential rate increases; therefore all residential rates (including Tier 1 and 2 rates) will reflect the full price of carbon, and no one class of residential ratepayers will bear disproportionate GHG costs in relation to any other class.

134. Bear Valley will receive a very small number of allowances under the Cap-and-Trade program, and the administrative cost of distributing GHG allowance revenues according to the methodology adopted in this decision would far exceed the value of the allowances received. Returning GHG allowances revenues volumetrically to Bear Valley's customers in proportion to GHG costs incurred is cost-effective and administratively simple to implement.

135. Application of the Conservation Incentive Adjustment ensures that lower-tier residential customers of both the investor-owned utilities and CCAs see no GHG costs in their rates.

136. To ensure competitive neutrality among investor-owned utilities and CCAs and Energy Service Providers, GHG compliance costs must be included in the generation component of customers' rates and allocated in the same manner that other generation costs are allocated to bundled customers.

137. Cap-and-Trade program costs are dependent on the investor-owned utilities' energy procurement costs that are reflected in the generation component of electricity tariffs. CCA and DA providers will have different Cap-and-Trade-related costs than the local investor-owned utility that provides distribution service to CCA and DA customers.

138. To ensure equitable treatment of investor-owned utility and CCA or DA residential and small business customers receiving a volumetric return, such customers must receive the same volumetric return in dollars per kWh regardless of whether they procure energy from an investor-owned utility or CCA or DA providers.

139. Consideration of clean energy or energy efficiency projects in this proceeding could be duplicative of existing proceedings and may result in

programs or projects being subject to different evaluation criteria, depending on the proceeding in which such programs or projects are presented.

140. The appropriate venue for deciding the manner in which GHG allowance revenues should be allocated toward energy efficiency and clean energy programs is within the various proceedings specifically opened to make such decisions.

141. We do not have adequate record at this time to adopt specific criteria for evaluating which clean energy or energy efficiency projects or programs should qualify to receive GHG allowance revenues in the future, if any, aside from the requirement that funding be additional to already existing program budgets.

142. Given the short timeframe in which to implement a customer outreach and education program after the enactment of SB 1018, customer education must be modest and targeted for 2013.

143. Customer outreach and education program benefits must be weighed against the cost of these programs in order to maximize both customer understanding of the Cap-and-Trade program and GHG allowance revenue returns to ratepayers.

144. The Cap-and-Trade program is a program of the State of California, not the investor-owned utilities.

145. The purpose of the customer outreach program is to notify and explain to recipients of GHG allowance revenue, at a minimum, that they are receiving a credit as a result of California's GHG Cap-and-Trade program. Outreach may occur through various channels including bill notices, website, direct customer outreach, and various media outlets.

146. Customer outreach efforts must ensure that hard-to-reach customers receive adequate information and education. This can be achieved through the use of ethnic media and community-based organizations, among other options.

147. Customer outreach and education programs must be competitively neutral.

148. It is infeasible to delegate customer outreach responsibilities to a third-party owned administrator in 2013.

149. No utility proposed a specific customer outreach and education program or budget for 2014 and beyond.

150. PG&E, SCE and SDG&E proposed initial budgets of \$1.7 million, \$1.4 million, and \$750,000, respectively, for customer outreach and education in 2013. PacifiCorp and CalPeco did not offer budgets for consideration.

151. PG&E, SCE, and SDG&E's proposed customer outreach budgets for 2013 represent approximately 0.4% for SCE, 0.7% for PG&E, and 1.1% for SDG&E of total GHG allowance revenues for each utility in 2013, using the ARB allowance floor price.

152. Given the nascent state of both the Cap-and-Trade program and of customer outreach and education activities, it is difficult to evaluate the appropriateness of PG&E, SCE, and SDG&E's proposed budgets for calendar year 2013.

153. There are likely to be economies of scale associated with the administration of a customer outreach program.

154. Approving customer education budgets for PacifiCorp and CalPeco up to 1.5% of GHG revenues, calculated at the ARB floor price for 2013, provides adequate funding for 2013. PacifiCorp's estimated 2013 customer education budget is \$110,000. CalPeco's estimated budget for 2013 is \$35,000.

155. In order to ensure that adequate funding is available for customer outreach and education, the utilities will need to set aside a portion of GHG allowance revenues to cover these costs before distribution of any revenues to EITE, small business, and residential customers.

156. The utilities will need to track customer outreach and education costs against revenues allocated to cover those costs.

157. System and billing upgrades may be necessary in order to implement the GHG revenue allocation methodology adopted in this decision.

158. There is not adequate record to approve administrative budgets for 2013 or subsequent years.

159. Administrative costs and GHG revenues applied to those costs must be tracked and reviewed for reasonableness.

160. It is appropriate to allocate customer outreach costs to those customers who will be the beneficiaries of the direct crediting of GHG allowance revenue.

161. It is appropriate to use GHG revenues to fund administrative costs.

162. In order to ensure that adequate funding is available for administrative activities, the utilities will need to set aside a portion of GHG allowance revenues to cover these costs before distribution of any funds to EITE, small business, and residential customers.

163. BART will face a similar mismatch in the amount of GHG revenue received as any DA or CCA customer and is not uniquely situated when compared to other non-bundled PG&E customers. BART is not an EITE or small business customer.

164. There are many implementation details that must be addressed related to the utilities' administration of the adopted GHG allowance revenue return methodology.

165. GHG costs for each compliance year are the GHG compliance costs incurred directly by the utilities for GHG emissions from their own facilities, contracts where they have assumed the cost of compliance on behalf of a third-party (either agreeing to compensate the third-party for the costs of their compliance obligations or where the investor-owned utility is responsible for procuring allowances on the third-party's behalf), or associated with electricity imports where the investor-owned utility is the compliance entity. In addition, GHG costs are the compliance costs incurred by the utilities through the GHG costs of electricity purchases in the wholesale market.

166. If GHG-related costs were immediately recoverable in rates before the GHG revenue allocation is implemented retail customers eligible to receive GHG allowance revenues would see only the cost increase without any countervailing revenues.

167. GHG costs must be deferred based upon approved 2013 cost forecasts in each utility's 2013 ERRRA or Energy Cost Adjustment Clause proceedings.

168. CCAs and Energy Service Providers could elect to defer the inclusion of GHG costs in their rates for the duration of the deferral of the investor-owned utilities' GHG costs to avoid any potential competitive disadvantage as a result of the deferral of the investor-owned utilities' GHG costs.

169. If CCAs and Energy Service Providers elect to immediately include GHG costs in rates, any competitive disadvantage will be offset by the competitive disadvantage experienced by the investor-owned utilities once they begin to amortize deferred GHG costs in rates.

170. It is appropriate on a prospective basis to establish GHG cost and revenue forecasts and reconcile realized GHG costs and revenues in a proceeding

separate from the utilities' ERRA, or other related proceedings for PacifiCorp and CalPeco.

171. It will be practically infeasible to determine actual GHG costs embedded in the market price of energy against which to apply GHG allowance revenues. A methodology must be developed to estimate actual GHG costs. A reasonable proxy may be the application of each utility's Commission-approved generation cost allocator applied to forecasted GHG costs.

172. ARB will need to provide the Commission's Energy Division with certain data in order to determine the correct amount of GHG allowance revenues to be credited to each EITE entity.

173. The administrative costs to implement the adopted GHG revenue allocation methodology may be excessive for PacifiCorp and CalPeco.

174. Implementation of Bear Valley's allowance revenue allocation approach should be straightforward and should not require any further action by the Commission.

175. Numerous parties filed motions in Track 1 Phase 1 of this proceeding requesting party status or seeking resolution of specific issues. To our knowledge, all outstanding motions have been addressed, either via electronic or written ruling.

Conclusions of Law

1. The Cap-and-Trade regulation at Sections 95892(d)(2-5) establishes limitations on the use of GHG auction proceeds and allowance revenue, including:

- Proceeds obtained from the monetization of allowances directly allocated to the investor owned utilities shall be subject to any limitations imposed by the California Public Utilities Commission;

- Auction proceeds and allowance value obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of the electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers;
- Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and CCAs;
- Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32, is prohibited including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.

2. Table 8-1 of § 95870 of the Cap-and-Trade regulation lists industries eligible to receive Industry Assistance and ranks their leakage risk as low, medium, or high.

3. Section 95891 of the Cap-and-Trade regulation sets forth the GHG allowance allocation methodology for those industries eligible to receive Industry Assistance.

4. Section 739.1, sets forth limitations on increases to rates in the CARE program, and § 739.9, sets the parameters by which all other non-CARE residential rates may be increased. The Commission's ability to increase PG&E, SCE and SDG&E's lower-tier (Tiers 1 and 2) residential rates (CARE and non-CARE) is limited throughout the duration of the Cap-and-Trade program.

5. Section 748.5 (a) requires that revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of GHG allowances to electric utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations to be credited directly to the residential,

small business, and emissions-intensive trade-exposed retail customers of the electrical corporation.

6. Section 748.5(b) mandates that the utilities adopt and implement, not later than January 1, 2013, a customer outreach plan, including, but not limited to, such measures as notices in bills and through media outlets, for purposes of obtaining the “maximum feasible public awareness” of the crediting of GHG allowance revenues.

7. Section 748.5(c) states that the Commission may allow investor-owned utilities to use up to 15% of the revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of GHG allowances to electrical distribution utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations, for clean energy and energy efficiency projects established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source.

8. The adopted GHG revenue allocation methodology should achieve the high priority policy objectives of preserving the carbon price signal, preventing economic leakage, reducing adverse impacts on low income households, and maintaining competitive neutrality. The adopted methodology should also distribute GHG revenues equitably recognizing the public asset nature of the atmospheric carbon sink, achieve administrative simplicity whenever possible, and promote customer awareness of the Cap-and-Trade program and its benefits.

9. The California Supreme Court has enunciated clear standards for courts or state agencies to use in construing a statute. The Commission must first look to the statute’s words and give them their usual and ordinary meaning. The

statute's plain meaning controls unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, the Commission must consider other aids, such as the statute's purpose, legislative history, and public policy. When more than one statutory construction is possible, the Commission should favor the construction that leads to the more reasonable result.

10. Section 748.5(a) prohibits granting a direct allocation of GHG revenues to customer groups that are not designated as residential, small business, or emissions-intensive and trade-exposed.

11. An appropriate statutory construction of the term "small business" in § 748.5(a) is a business with electric demand that does not exceed 20 kW in more than three months within a 12-month period.

12. It is reasonable to extend the small business designation to all non-residential customers on General Service or Agricultural tariffs that meet the usage requirements adopted in this decision.

13. At a minimum, an appropriate statutory construction of the term "emissions-intensive and trade-exposed" in § 748.5(a) is any entity in an industry that qualifies for Industry Assistance, regardless of the amount of emissions produced. Should ARB modify eligibility for Industry Assistance, such modifications should extend to entities for the purposes of receiving GHG allowance revenue for indirect emissions.

14. Entities that are part of industrial sectors that qualify for Industry Assistance, but with emissions levels less than 25,000 MTCO₂e, should be required to voluntarily opt-into the Cap-and-Trade program in order to be eligible to receive allowance revenue for the indirect emission costs associated with their electricity purchases, unless another method can be developed to

accurately obtain the necessary information to calculate revenue returns for these customers.

15. Duplicative distribution of GHG allowance revenue to customers that are designated as EITE and also qualify as small businesses should be avoided. It is reasonable to require the utilities to propose a methodology to avoid duplicative distribution of allowance revenues to these entities.

16. Promptly following the issuance of this decision, the Commission should conduct a process to explore whether certain industrial sectors not currently eligible for Industry Assistance (because they do not have a direct compliance obligation under the Cap-and-Trade program) may become emissions-intensive and trade-exposed as a result of exposure to GHG costs from electricity purchases. We anticipate the assigned Commissioner or assigned ALJs will set forth the process by which the Commission will undertake an evaluation of this issue.

17. "Maximum feasible public awareness," as set forth in § 748.5(b) should be viewed as a flexible standard.

18. It is reasonable to focus our efforts on maximizing the amount, and therefore, benefit, of GHG allowance revenue returned to EITE, small business and residential customers. Customer outreach and education expenditures should be evaluated against achievement of this programmatic goal.

19. Pursuant to § 748.5(b), GHG allowances revenues should be used to fund customer outreach and education programs related to the direct return of GHG allowance revenues.

20. Nothing in § 454 precludes the Commission from considering issues of equity or undertaking a cost/benefit analysis in allocating revenue requirements differently to different ratepayer classes or groups.

21. Customer outreach and education pursuant to § 748.5(b) should be modest and low-cost, especially in the earlier years. A more robust program should be developed for later years of the Cap-and-Trade program.

22. A reasonable statutory construction of § 748.5(c) is that the statute imposes a cap, but does not set a minimum or specific requirement, on the amount of allowance revenues that may be directed towards energy efficiency or clean energy projects.

23. It is reasonable to interpret “established pursuant to statute” as set forth in § 748.5(c) to mean that the Commission may direct funding towards any energy efficiency or clean energy project or program it deems appropriate that falls under the purview of the broad statutory authority already granted to the Commission to develop and implement energy efficiency and clean energy programs.

24. Pursuant to § 748.5(c), GHG allowance revenues should not be used to fund clean energy or energy efficiency programs or projects previously paid for by general ratepayer funds unless such existing funds are directed toward new energy efficiency or clean energy projects within the same program. Any funding of clean energy or energy efficiency by GHG allowance revenues should be additional to funding already provided through general ratepayer funds.

25. To ensure that sectors with a higher leakage risk receive proportionally greater transition assistance for increased electricity costs, it is reasonable to distribute GHG allowance revenues to EITE entities in a parallel manner to the way ARB allocates allowances for direct emissions under ARB’s Industry Assistance program.

26. Should the Commission expand the definition of EITE entities to include sectors or industries not covered under ARB’s Industry Assistance allocation

methodology, to the extent practical, the GHG allowance revenue allocation methodology for such entities should rely on methodologies that are similar to those ultimately adopted to return GHG allowance revenues to EITE customers that qualify for Industry Assistance under ARB's Cap-and-Trade regulation.

27. EITE customers should receive similar GHG revenue allocations regardless of whether the EITE entity purchases or consumes electricity from its own CHP facility, a third-party owned CHP facility, or from an investor-owned utility or DA provider.

28. It is appropriate to use GHG allowance revenues to address the GHG costs of electricity purchased by refineries and other EITE entities from third-party owned CHP.

29. It is reasonable to require the utilities to return GHG allowance revenues to EITE entities in a manner that facilitates transparency and customer understanding. An on-bill credit, if ultimately adopted in a subsequent decision, should be denoted as a separate line-item and should be applied to the delivery component of the bill to ensure that all customers within a utility's service territory, irrespective of whether they are a bundled, DA, or CCA customer, are treated equally.

30. Pursuant to § 748.5(a), it is appropriate to provide small businesses with transition assistance to ease such businesses into the Cap-and-Trade program and to provide additional time and capital to help small businesses invest in strategies to reduce their exposure to GHG costs.

31. It is reasonable to apply the ARB low-leak risk Industry Allocation Factor to the volumetric distribution of GHG allowance revenues to small business customers.

32. The investor-owned utilities should be required to return GHG allowance revenues to small business customers via an on-bill credit against their electricity purchases denoted as a separate line-item on bills. This bill credit should be applied to the delivery component of the bill to ensure that all customers within a utility's service territory, irrespective of whether they are a bundled, DA, or CCA customer, are treated equally.

33. It is reasonable to offset GHG costs in residential rates to avoid inequity between lower-tier and upper-tier residential rates and to avoid inclusion of disproportionate GHG costs in upper-tier residential rates.

34. It is reasonable to neutralize GHG costs in residential TOU rates in order to avoid the perverse incentive for residential customers to stay on tiered rates when they might otherwise choose to move to TOU rates.

35. GHG costs in residential rates should be neutralized at the time such costs are incurred (on a monthly basis) in order to prevent upper-tier residential customers from seeing a carbon price signal in their rates.

36. GHG costs in residential rates should be neutralized via application of GHG revenues to a delivery rate component that all customers, including DA and CCA customers, pay.

37. It is in the public interest to return all remaining GHG allowance revenues (after the compensation of EITE and small business customers and the neutralization of GHG costs in residential rates) to all residential customers on an equal per-residential account basis (the climate dividend) to offset the increased costs of goods and services in the economy that will occur when electricity costs increase as a result of the Cap-and-Trade program and that will ultimately be borne by all residential customers, including low-income residential customers.

38. It is reasonable to return the climate dividend to residential customers on a per-residential account basis via a semi-annual on-bill credit commencing no sooner than six months from the start of the Cap-and-Trade program, January 1, 2013.

39. If the climate dividend exceeds a customer's monthly bill, the remaining climate dividend should be applied toward the subsequent month's bill until the climate dividend is exhausted, unless certain circumstances preclude this method of distribution.

40. Pursuant to §§ 739.5 (a) and (b), residential customers receiving service under a master-meter configuration should receive an equitable portion of GHG allowance revenues. Residential households with master-meter configurations should receive their proportional share of the climate dividend. The Commission should promptly address this issue.

41. It is appropriate to adopt an interim cash-out provision for customers participating in net-energy metering similar to that adopted in D.11-06-016. Net-energy metering customers that face stranded revenue value over the twelve-month period following the month in which the climate dividend is applied should receive the cash value of the revenues.

42. It is reasonable to require PacifiCorp and CalPeco to return revenues according to the same general methodology as adopted for PG&E, SCE, and SDG&E (including implementation of a customer education program) with one exception. Because all of PacifiCorp and CalPeco's residential rates are able to reflect the carbon price signal, PacifiCorp and CalPeco will not need to offset GHG costs in residential rates. Thus, after compensating EITE and small-business customers, PacifiCorp and CalPeco should return all remaining GHG allowance revenues to residential customers on an equal per-account basis.

43. It is reasonable to require that Bear Valley return 100% of GHG allowance revenues, including interest, on a volumetric basis to its customers in proportion to costs borne through its existing, annual Power Purchase Adjustment Clause proceeding. If Bear Valley's customer base increases significantly in size or estimated allowance revenues increase substantially in the future, it may be prudent to reconsider whether a different distribution mechanism is appropriate at that time.

44. To ensure equal treatment of residential and small business customers of investor-owned utilities and CCA and DA providers receiving a volumetric return of GHG revenues, the dollar per kWh magnitude of the volumetric return should be equivalent across such customers, regardless of whether those customers procure energy from an investor-owned utility or from CCA or DA providers.

45. It is appropriate to return all GHG revenues, with the exception of those revenues directed toward customer education and administrative costs, directly to EITE, small business and residential ratepayers.

46. Should the Commission decide at a later date to direct GHG revenues toward energy efficiency or clean energy programs or projects, such projects should have as a stated and measurable goal a reduction in GHG emissions.

47. It is reasonable to require the investor-owned utilities to develop and implement a modest and low-cost competitively neutral customer outreach and education program on behalf of their bundled customers and customers of CCA and DA providers.

48. Customer outreach in 2013 should, at a minimum, be targeted toward those customers receiving GHG allowance revenue. Customer outreach should be expanded to customers that will not receive a GHG allowance revenue return,

budget permitting. Materials should be designed to notify and explain to recipients of allowance value that they are receiving a credit as a result of California's Cap-and-Trade program. Appropriate outreach channels may include bill notices, websites, direct customer outreach, and various media outlets. Outreach efforts should ensure that hard-to-reach customers receive adequate information and education. This can be achieved through the use of ethnic media and community based organizations, among other options. Customer outreach should occur in advance of and concurrent with the distribution of any GHG allowance revenues. CCA and DA providers should have the opportunity to review the investor-owned utilities' 2013 customer outreach plans prior to filing of plans for approval.

49. All customer outreach and education materials addressing the distribution of GHG allowance revenues should attribute the distribution of revenues to the State of California or California's Cap-and-Trade program. Any communications from an investor-owned utility to DA and CCA customers pertaining to the distribution of GHG allowance revenues or the Cap-and-Trade program should include the logos of both the investor-owned utility and the CCA or Energy Service Provider.

50. It is reasonable to require the utilities to distribute to their customers communications from the Commission providing information about the State of California's Cap-and-Trade program. The timing of such communications should be at the election of the Director of the Energy Division, and the costs of the communications should be funded through the utilities' customer outreach budgets for 2013. These communications should be absent any particular utility logo.

51. It is appropriate to expand customer awareness of the purpose and value of GHG allowance revenues in 2014 and beyond.

52. It is reasonable to require the utilities, in consultation with CCA and DA providers, and pending approval of the Director of Energy Division, to hire an outside marketing and public relations firm to propose expanded customer outreach and education activities through 2015, including evaluating the feasibility and potential advantages and disadvantages of a third-party administrator for customer outreach and education activities on a prospective basis. The final scope of work should be developed in consultation with and approval by the Director of the Energy Division in advance of the release of any documents soliciting offers. The final hiring decision should be approved by the Director of the Energy Division. A reasonable budget is \$500,000. The costs of the marketing and public relations firms should be borne by PG&E, SCE, and SDG&E in proportion to their percentage of retail sales and should be funded with GHG allowance revenues.

53. It is reasonable to approve PG&E, SCE, and SDG&E's proposed budgets of \$1.7 million, \$1.4 million, and \$750,000, respectively, to cover customer outreach and education costs in 2013. These budgets should not include the cost to hire a marketing and public relations firm. PacifiCorp and CalPeco should be authorized to allocate an appropriate portion of GHG revenues to cover customer outreach and marketing efforts in 2013.

54. It is reasonable to expect that PacifiCorp and CalPeco's customer outreach budgets for 2013 will represent about the same percentage of their respective allowance revenues for 2013 as SDG&E's expenses because SDG&E is the smallest of the three large investor-owned utilities. Some cushion is appropriate

in recognition of the economies of scale enjoyed by the larger utilities, including SDG&E.

55. It is reasonable to authorize PacifiCorp and CalPeco to budget up to 1.5% of their expected GHG allowance revenue at the 2013 ARB floor price for customer outreach and education expenditures in 2013. This yields budgets of approximately \$110,000 for PacifiCorp and \$35,000 for CalPeco.

56. Customer outreach and education costs should be tracked in a memorandum account.

57. The utilities should allocate GHG revenues toward customer education before distribution of remaining revenues to EITE, small business and residential ratepayers. Any remaining customer outreach and education funds at the end of a calendar year should be rolled over for use in subsequent years.

58. Up front and ongoing administrative expenditures should be funded by GHG revenues and should be subject to reasonableness review. Administrative costs should be tracked in a memorandum account.

59. The utilities should allocate GHG revenues toward administrative costs before distribution of remaining revenues to EITE, small business and residential ratepayers. Any remaining administrative funds at the end of a calendar year should be rolled over for use in subsequent years.

60. BART should not receive a set-aside of GHG revenues.

61. GHG costs should not be included in rates until necessary implementation details of the adopted GHG revenue allocation methodology are resolved.

62. PG&E, SCE, and SDG&E, PacifiCorp, and CalPeco should record estimated GHG costs, including interest, for subsequent recovery in rates in a new GHG sub-balancing account. Estimated GHG costs should be the 2013 forecasted GHG costs in each utility's ERRA or Energy Cost Adjustment Clause mechanism.

Estimated GHG revenues should be recorded and deferred in a new GHG Revenue Balancing Account.

63. The deferral of GHG costs in the investor-owned utilities rates pending finalization of implementation details does not violate 17 CCR § 95892(d)(4).

64. To ensure accurate representation of rates to all customers, any communications of existing investor-owned utility rates to customers shared by the investor-owned utility and a CCA or Energy Service Provider should accurately disclose their respective deferred GHG costs to provide a direct comparison across rates.

65. PG&E, SCE, SDG&E, PacifiCorp, and CalPeco should file a Tier 1 advice letter within 30 days of the effective date of this decision establishing GHG sub-balancing accounts and GHG Revenue Balancing Accounts.

66. Upon determination by the Commission that the GHG revenue allocation methodology is ready to be implemented, which shall occur through a written letter issued by the Director of the Energy Division and served on the service list of this proceeding (following the adoption of necessary decisions addressing implementation in this proceeding), the utilities should simultaneously begin the prospective allocation of GHG-related costs to all customers. The outstanding cost and revenue balances accumulated in the GHG cost sub-account and the GHG Revenue Balancing Account should be amortized over a reasonable period so that all deferred costs are recovered and all deferred revenues are distributed within 24 months. Interest should be accrued at the standard Commission-approved interest rate traditionally used for accruals in balancing accounts.

67. For the first three years of the Cap-and-Trade program, the utilities, with the exception of Bear Valley, should file an application setting forth forecasted GHG costs for the subsequent year and forecasted GHG revenues to be

distributed to each eligible customer class. Customer outreach and administrative costs should also be forecast. Beginning in 2014, applications should also include a detailed accounting of GHG costs incurred for the previous year (based upon a method to be approved in a subsequent phase of this proceeding) as well as revenues distributed, including customer outreach and administrative costs. Customer outreach and administrative costs should be subject to reasonableness review.

68. The Commission's Energy Division should initiate a public workshop process whereby interested parties may provide feedback on the proposed EITE and small business allocation formulas set forth in Appendices A and B. The workshop process should identify required input sources as well as the timing of all information and data exchanges that must occur to calculate revenue return. The workshop process should also explore the appropriate timing and form (e.g. on-bill or off-bill) of GHG revenue distribution to EITE and small business customers. Finally, the workshop should explore alternative options to the requirement to opt-into the Cap-and-Trade program for EITE entities within sectors designated as eligible for Industry Assistance by ARB with emissions less than 25,000 MTCO_{2e} in order to obtain necessary data to calculate a GHG revenue return. Energy Division should prepare and submit a workshop report addressing the implementation of formulas, and parties should have an opportunity to provide comment prior to the issuance of a Commission decision adopting finalized formulas and calculation methodologies. Minor updates to finalized and adopted formulas should be made as necessary by Energy Division through issuance of a resolution with opportunity for stakeholder input and comment.

69. It is appropriate to authorize the Commission's Energy and Legal Divisions to enter into an interagency agreement with ARB in order to facilitate the exchange of all necessary data and information to calculate the EITE GHG revenue return, including any necessary confidentiality agreements to protect market sensitive information.

70. It is reasonable to require the utilities, with the exception of Bear Valley, to submit an implementation report addressing how each utility intends to implement the adopted GHG revenue allocation methodology. The primary purpose of the report should be to explain how the investor-owned utility will apportion allowance revenue for each of the purposes authorized in this decision, given the uncertainty surrounding both the total amount of allowance revenue that the utilities will receive and have on hand at any given moment and the amount of revenue that will be necessary to compensate EITE, small business, and residential customers and to pay for customer education and general administrative costs incurred to implement this decision. It is appropriate to review and approve the utilities' implementation reports through the issuance of one or more subsequent decisions.

71. It is reasonable to allow PacifiCorp and CalPeco flexibility, as needed, to implement the GHG allowance revenue allocation methodology adopted in this decision. PacifiCorp and CalPeco should provide a detailed explanation to justify any deviations, and deviations should be subject to review and approval by the Commission.

72. Implementation of Bear Valley's GHG revenue allocation methodology should not require any further action by the Commission.

73. It is reasonable to require the utilities, with the exception of Bear Valley, to file Tier 2 advice letters setting forth the scope and timing of their proposed

customer outreach activities for 2013. The utilities should solicit input from CCA and DA providers prior to the filing of the advice letters.

74. The utilities, with the exception of Bear Valley, should be required to submit an application for approval of their customer education and outreach programs for 2014 and beyond, including estimated yearly budgets.

75. It is reasonable to deny any outstanding motions in Track 1 Phase 1 of this rulemaking.

76. There are no disputed issues of fact; therefore, evidentiary hearings are not necessary in Track 1 of Phase 1 of this proceeding.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company are directed to distribute greenhouse gas allowance revenues, inclusive of interest, resulting from the consignment of the assigned allowances allocated to the utilities by the California Air Resources Board to auction, in the following manner (after first setting aside an appropriate amount of greenhouse gas allowance revenues to fund customer outreach and education activities and initial and on-going administrative costs):

- A. Compensate emissions-intensive and trade-exposed entities (as defined in this decision) using methodologies based upon those developed by the California Air Resources Board to address direct emissions cost exposure under the Cap-and-Trade program, as preliminarily set forth, but not adopted, in Appendix A to this decision;
- B. Offset the rate impacts of the Cap-and-Trade program in the electricity rates of small businesses, defined as entities

with monthly demand not exceeding 20 kilowatts in more than three months in a twelve-month period, through a volumetrically calculated rate adjustment, preliminarily set forth, but not adopted, in Appendix B to this decision.

- C. Neutralize the rate impacts of the Cap-and-Trade program in residential electricity rates through a volumetrically calculated rate adjustment;
- D. Distribute all revenues remaining after accounting for the revenues allocated pursuant to the prior three uses to residential customers on an equal per residential account basis delivered as a semi-annual, on-bill credit.

2. PacifiCorp and California Pacific Electric Company are directed to return revenues according to the process set forth in Ordering Paragraph # 1, with one exception. PacifiCorp and California Pacific Electric Company must return all remaining greenhouse gas allowance revenues, after compensating emissions-intensive and trade-exposed entities and small business customers, directly to their residential ratepayers on an equal per residential account basis delivered semi-annually via an on-bill credit (thus skipping Step C in Ordering Paragraph # 1, above).

3. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are directed to allocate greenhouse gas allowance revenues to all customers in the applicable customer groups set forth in this decision inclusive of Direct Access and Community Choice Aggregation customers in a competitively neutral manner as required by the Cap-and-Trade regulation. Direct Access and Community Choice Aggregation customers must receive their proportional share of greenhouse gas revenues, and such revenues must be dispersed according to the methodology set forth in Ordering Paragraph # 1. Greenhouse gas compliance costs must be included in the generation component of customers'

rates and allocated in the same manner that other generation costs are allocated to bundled customers.

4. Bear Valley Electric Service, a division of Golden State Water Company, as a small utility receiving minimal greenhouse gas allowance revenue, is ordered to return 100% of its greenhouse gas allowance revenue in direct proportion to costs borne by its customers (a volumetric return) through its existing, annual Purchase Power Adjustment Clause proceeding.

5. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are directed to allocate an appropriate portion of greenhouse gas allowance revenues to refineries and other emissions-intensive and trade-exposed entities with third-party-owned combined heat and power units to avoid disparate treatment between third-party-owned and customer host-owned combined heat and power. A preliminary methodology is set forth, but not adopted, in Appendix A.

6. Emissions-intensive and trade-exposed customers with emissions less than 25,000 MTCO₂e and that operate in sectors that qualify for Industry Assistance under the California Air Resources Board Cap-and-Trade regulation must voluntarily opt-into the Cap-and-Trade program in order to be eligible to receive allowance revenue for the indirect emission costs associated with their electricity purchases, unless, in a subsequent phase of this proceeding, another method can be developed to accurately obtain the necessary information to calculate greenhouse gas allowance revenue returns for these customers.

7. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are directed to return greenhouse gas allowance revenues to small

business customers, as defined in this decision, via a volumetrically calculated on-bill credit against their electricity purchases denoted as a separate line-item on bills. This bill credit shall be applied to the delivery component of the bill to ensure that all customers within a utility's service territory, irrespective of whether they are a bundled, Direct Access, or Community Choice Aggregator customer, are treated equally.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company are directed to neutralize greenhouse gas costs in all residential rates, including time-of-use rates, through the volumetric return of greenhouse gas allowance revenues in an amount equivalent to, and not exceeding, the Cap-and-Trade program costs that are embedded in residential rates. Greenhouse gas costs in residential rates must be offset at the same time such costs are incurred, that is the same month that residential customers experience Cap-and-Trade program costs in rates. Greenhouse gas revenues must be returned to all customers, including bundled, Direct Access, and Community Choice Aggregator customers, via a delivery rate component that all residential customers pay.

9. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are directed to allocate all remaining greenhouse gas allowance revenues to residential ratepayers on a per-residential account basis (after compensating emissions-intensive and trade-exposed entities and small business customers and neutralizing greenhouse gas costs in residential rates). An individual residential customer's return shall be calculated by dividing remaining greenhouse gas allowance revenues (inclusive of those associated with Community Choice Aggregator and Direct Access customers) net of the

revenues set aside to fund customer outreach and education and administrative costs, net of the revenues used to compensate emissions-intensive and trade-exposed entities and small businesses, and net of the revenues used to neutralize greenhouse gas costs in residential rates, by the number of residential accounts taking distribution service from the utility. This return shall be known as the climate dividend. The climate dividend must be credited via a semi-annual, on-bill credit commencing no sooner than six months from January 1, 2013. In the event that the climate dividend exceeds a customer's monthly bill, the excess must be applied to the subsequent month's bill until the climate dividend is exhausted, circumstances permitting.

10. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are directed to return the excess cash value of the climate dividend to residential net-energy metering customers whose climate dividend exceeds their electricity bills over the twelve-month period following the month in which a non-volumetric credit is applied.

11. For calendar year 2013, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company (the investor-owned utilities) are directed to develop and administer a competitively neutral customer outreach and education program on behalf of all customers receiving greenhouse gas allowance revenue, including customers of Community Choice Aggregator and Direct Access providers. Outreach efforts may extend to customers not receiving greenhouse gas revenues, budget permitting. Outreach shall occur through various channels including bill notices, websites, direct customer outreach, and various media outlets, and shall occur in advance of and concurrent with the

distribution of any greenhouse allowance revenues. Outreach efforts must ensure that hard-to-reach customers receive adequate information and education about greenhouse gas revenues. All messaging must be developed in a way that does not advantage the investor-owned utility over the Community Choice Aggregator and Direct Access providers within its service territory. Descriptions in outreach and education materials of the Cap-and-Trade program and the various greenhouse gas allowance revenue returns authorized in this decision must be attributed to the State of California or the State of California's Cap-and-Trade Program. Any communications from the investor-owned utilities to Community Choice Aggregator and Direct Access customers pertaining to the Cap-and-Trade program and the various greenhouse gas allowance revenue returns authorized in this decision must include both the logo of the investor-owned utility and the Community Choice Aggregator or Direct Access provider. The investor-owned utilities are authorized to develop the content and messaging of their general outreach and education activities in consultation with Community Choice Aggregator and Direct Access providers. The scope, timing and activities of the utilities' proposed outreach and education activities must ultimately be approved by the Commission, as set forth in Ordering Paragraph # 27. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company will, upon request from the Director of the Energy Division, distribute to their customers communications from the California Public Utilities Commission providing information about California's Greenhouse Gas Cap-and-Trade program. These communications must be absent any utility logo. The timing of such communications will be at the election of the Director of the Energy Division, and the costs of the communications will be funded through the

utilities' 2013 customer outreach budgets, set forth in Ordering Paragraphs # 14 and 15.

12. By April 1, 2013, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company, in consultation with Community Choice Aggregator and Direct Access providers, are directed to hire, upon approval of the Director of the California Public Utilities Commission's Energy Division, a firm with marketing and public relations expertise. The firm must also evaluate the feasibility and benefit of the use of a third-party administrator for customer outreach and education activities going forward. The firm will be responsible for proposing expanded customer education activities through 2015. The final scope of work must be developed in consultation with and subject to approval by the California Public Utilities Commission's Energy Division Director in advance of the release of any documents soliciting offers. The selected marketing firm must submit its findings and recommendations to the investor-owned utilities, Community Choice Aggregator and Direct Access providers, and to the California Public Utilities Commission's Energy Division director no later than July 1, 2013. The report must also be served on the service list for Rulemaking 11-03-012.

13. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company are authorized to expend no more than \$500,000, which shall be funded by greenhouse gas allowance revenues, for the marketing and public relations firm set forth in Ordering Paragraph # 12 with the costs to be borne in proportion to their percentage of retail sales.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company are authorized to spend up to \$1.7

million, \$1.4 million, and \$750,000, respectively, on customer outreach and education activities in 2013. These budgets do not include the costs to hire the marketing and public relations firm set forth in Ordering Paragraph # 13. Subsequent years' budgets shall be approved according to the process set forth in Ordering Paragraphs # 23 and 24.

15. PacifiCorp and California Pacific Electric Company are authorized to spend up to 1.5% of their expected greenhouse gas allowance revenue, calculated at the 2013 California Air Resources Board Floor Price, for customer outreach and education expenditures in 2013. The approximate budget for PacifiCorp is \$110,000. The approximate budget for California Pacific Electric Company is \$35,000. Subsequent years' budgets shall be approved according to the process set forth in Ordering Paragraphs # 23 and 24.

16. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company PacifiCorp, and California Pacific Electric Company are directed to set aside greenhouse gas revenues to cover customer outreach and education efforts in advance of distributing remaining greenhouse gas revenues to emissions-intensive and trade-exposed, small business, and residential customers. Customer outreach costs must be tracked in a memorandum account. Any remaining customer outreach and education funds at the end of a calendar year must be rolled over for use in subsequent years.

17. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company PacifiCorp, and California Pacific Electric Company are authorized to use greenhouse gas revenues to fund initial and ongoing administrative costs necessary to the implementation of the greenhouse gas revenue allocation methodology adopted in this decision. Administrative costs must be tracked in a memorandum account and are subject to

reasonableness review. Any remaining administrative funds at the end of a calendar year must be rolled over for use in subsequent years.

18. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp and California Pacific Electric Company are directed to set aside greenhouse gas revenues to cover administrative costs before distributing remaining greenhouse gas revenues to emissions-intensive and trade-exposed, small business, and residential customers.

19. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp and California Pacific Electric Company must file Tier 1 Advice Letters within 30 days of the issuance of this decision showing establishment of memorandum accounts to track customer outreach and administrative costs, as set forth in Ordering Paragraphs # 16 and 17.

20. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company are ordered to defer including in rates all GHG costs and revenues, including accrued interest, until all necessary implementation details are finalized. Greenhouse gas costs will be based upon the 2013 greenhouse gas forecast approved in each utility's Energy Resource Recovery Account or Energy Cost Adjustment Clause forecast proceeding. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company must record estimated greenhouse gas costs for subsequent recovery in rates in a new greenhouse gas sub-balancing account. Estimated greenhouse gas revenues must be recorded and deferred in a new greenhouse gas Revenue Balancing Account.

21. Upon declaration by the California Public Utilities Commission that the greenhouse gas allocation methodology is ready for implementation, which shall occur upon the issuance and service of a letter on the service list of Rulemaking 11-03-012 by the Director of the Energy Division (following the adoption of all necessary decisions addressing implementation), Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company may simultaneously begin the prospective allocation of greenhouse gas-related costs and provide greenhouse gas revenues to eligible customer classes. The outstanding cost and revenue balances in the greenhouse gas sub-balancing account and the greenhouse gas Revenue Balancing Account, including accrued interest, must be amortized over a reasonable period so that all deferred costs and revenues are distributed within 24 months.

22. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company must file a Tier 1 advice letter within 30 days of the effective date of this decision establishing greenhouse gas sub-balancing accounts and greenhouse gas Revenue Balancing Accounts to track greenhouse gas costs and revenues.

23. For the first three years of the Cap-and-Trade program (2013-2015), Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp and California Pacific Electric Company must file an application by August 1 of 2013, 2014, and 2015 setting forth forecasted greenhouse gas costs for the subsequent year and forecasted greenhouse revenues to be distributed to eligible customer classes. Customer outreach and administrative costs must also be forecast. These applications may be

consolidated to facilitate consistency in policy and process and allow for the efficient participation of interested parties.

24. Beginning in 2014, the applications set forth in Ordering Paragraph # 23 must also include a detailed accounting of greenhouse gas costs incurred for the previous year as well as revenues distributed, including customer outreach and administrative costs. The methodology to calculate realized greenhouse gas costs will be finalized through a subsequent decision addressing implementation details, as set forth in Ordering Paragraphs # 27 and # 28. Customer outreach and administrative costs will be subject to reasonableness review. If, after three application cycles, the California Public Utilities Commission finds that forecasting and reconciling greenhouse gas costs and revenues becomes more ministerial, greenhouse gas costs and revenues may be evaluated and approved going forward in another appropriate proceeding.

25. Within 60 days of the issuance of this decision (with the date to be modified at the election of the Assigned Commissioner or assigned Administrative Law Judges), the California Public Utilities Commission's Energy Division is directed to initiate a public workshop process whereby interested parties may provide feedback on the proposed greenhouse gas revenue allocation formulas set forth in Appendices A and B for emissions-intensive and trade-exposed and small business customers. The workshop process must identify required input sources as well as the timing of all information and data exchanges that must occur to calculate revenue return. The workshop process must also explore possible alternative methods to the requirement to opt into the Cap-and-Trade program to obtaining necessary information to calculate the greenhouse gas revenue to emissions-intensive and trade-exposed entities designated as eligible for Industry Assistance under the California Air Resources

Board Cap-and-Trade regulation with annual emissions less than 25,000 metric tons of carbon-dioxide equivalent. The workshop process must explore the appropriate timing of greenhouse gas revenue distribution to emissions-intensive and trade-exposed and small business customers as well as the form the revenue return should take, whether on-bill or an off-bill credit. The California Public Utilities Commission's Energy Division must prepare and submit a workshop report providing recommended formulas, including all necessary information and data exchange details. The workshop report must also include recommended timing of the distribution of greenhouse gas allowances to emissions-intensive and trade-exposed and small business customers. The assigned Commissioner or assigned Administrative Law Judges may modify the date or required contents of the workshop report. Parties to this proceeding will have the opportunity to comment on the workshop report. The Commission anticipates issuing a decision adopting finalized greenhouse gas revenue distribution formulas and calculation processes. The California Public Utilities Commission's Energy Division is authorized to undertake minor updates to finalized formulas as necessary through the issuance of a resolution with opportunity for stakeholder input and comment.

26. The California Public Utilities Commission's Energy Division and Legal Division are authorized to enter into an interagency agreement with the California Air Resources Board to facilitate the exchange of all necessary data and information, including any necessary confidentiality agreements to protect market sensitive information, to calculate the greenhouse gas allowance revenue return for emissions-intensive and trade-exposed entities.

27. No later than 45 days after the effective date of this decision (with the date to be modified at the election of the assigned Commissioner or assigned

Administrative Law Judges), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) must file a joint report in Rulemaking 11-03-012 addressing implementation details for the adopted greenhouse gas revenue allocation methodology. Formulas for distribution to emissions-intensive and trade-exposed and small business customers may not be finalized at the time of filing. If necessary, PG&E, SCE, and SDG&E may submit amended filings. Following issuance of this decision, a ruling will issue in Rulemaking 11-03-012 finalizing the required contents of the utility reports. The Commission anticipates issuing a decision addressing PG&E, SCE, and SDG&E's implementation plans.

28. No later than 30 days after Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company have filed their joint implementation report, as set forth in Ordering Paragraph # 27 (with the date to be modified at the election of the assigned Commissioner or assigned Administrative Law Judges), PacifiCorp and California Pacific Electric Company must each file a report in Rulemaking (R.) 11-03-012 addressing implementation details for the adopted greenhouse gas revenue allocation methodology. Formulas for distribution to emissions-intensive and trade-exposed and small business customers may not be finalized at the time of filing. If necessary, PacifiCorp and California Pacific Electric Company may submit amended filings. Following issuance of this decision, a ruling will issue in R.11-03-012 finalizing the required contents of the utility reports. To the extent that PacifiCorp or California Pacific Electric Company wish to modify the greenhouse gas revenue allocation methodology adopted in this decision to keep their implementation and ongoing administrative costs relatively small in proportion to the allowance revenues they receive, these companies must describe in the report the

modifications they plan to make and provide justification for these modifications. The Commission anticipates issuing a decision addressing PacifiCorp and California Pacific Electric Company's proposed implementation plans.

29. No later than 30 days after Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, PacifiCorp and California Pacific Electric Company file their implementation reports, as set forth in Ordering Paragraph # 27, each utility must file a Tier 2 Advice Letter setting forth the scope and estimated timing of proposed customer outreach activities for 2013 consistent with the requirements set forth in Ordering Paragraph # 11. The utilities must solicit input from Community Choice Aggregator and Direct Access providers prior to the submission of the Tier 2 Advice Letter. The Tier 2 Advice Letters must clearly describe, including examples if necessary, the presentation of the separate on-bill line-item for the return of the climate dividend to residential customers.

30. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, PacifiCorp, and California Pacific Electric Company must file an application by September 1, 2013 setting forth their proposed customer outreach plan for 2014 and 2015, incorporating the results of the consultant's report set forth in Ordering Paragraph # 12 and including estimated yearly budgets.

31. By July 1, 2015, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, PacifiCorp, and California Pacific Electric Company must file an application setting forth their proposed customer outreach and education plan for 2016-2020, including estimated yearly budgets.

32. Bear Valley Electric Service, a division of Golden State Water Company is authorized to include greenhouse gas costs and revenues in rates based on annual forecasts approved by the California Public Utilities Commission in its Purchase Power Adjustment Clause proceeding, which shall be adjusted through the use of balancing accounts based on actual costs incurred and greenhouse gas allowance revenues received.

33. Any outstanding motions in Track 1 Phase 1 of Rulemaking 11-03-012 are denied.

34. Hearings are not needed in Track 1 Phase 1 of this proceeding.

35. Rulemaking 11-03-012 remains open.

This order is effective today.

Dated December 20, 2012, at San Francisco, California

MICHAEL R. PEEVEY

President

TIMOTHY ALAN SIMON

MICHEL PETER FLORIO

CATHERINE J.K. SANDOVAL

MARK J. FERRON

Commissioners

APPENDIX A:
Sample Methodologies for Calculating Allowance Value to
Compensate EITE Customers for their Purchased Electricity Costs
Resulting from the Cap-and-Trade Program

In this Appendix we detail proposed methodologies and associated formulas consistent with the direction provided in this decision to calculate the amount of revenues entities eligible for Industry Assistance would receive to compensate them for the indirect emissions costs they are subject to under the Cap-and-Trade program as a result of their electricity purchases. These formulas are substantially based on those developed by the Air Resources Board to calculate allowance allocations that entities are eligible to receive to address direct emissions costs. As described in detail below, depending on industrial classification and activity, a different methodology and formula may apply.

In developing these proposed methodologies and formulas we seek to mirror those ARB developed for purposes of distributing emission allowances, recognizing that in the context of this decision, we are allocating revenues, not allowances. This and other factors necessitate modifications to the ARB formulas to make them applicable to address revenue allocation. Going forward we seek to refine these formulas and inputs through technical workshops and ultimately a Commission-adopted resolution. However, in making any refinements, we will seek to maintain ARB's basic conceptual and methodological approach.

Product-Based Allocation Methodology

Under this methodology, ARB applies the following general formula to determine the allocation of allowances that an entity would receive:

$$\text{Allocation} = A * B * C * O$$

Where:

“A” is the “assistance factor,” which is the percent of the emissions benchmark (described below) that will be provided in an allocation, ranging from 30% to 100%, depending on sector’s leakage risk classification (high: 100% for all compliance periods; medium: 100%, 75%, and 50% for the first, second, and third compliance periods, respectively; and low: 100%, 50%, 30%). The specific percentage is determined based on ARB determinations regarding the level of emissions intensity and trade exposure an entity is subject to and the year in which the allocation is being sought. The specific Assistance Factor that applies to a given sector can be found in Table 8-1 of the ARB’s cap-and-trade regulation.

“B” is the emissions benchmark per unit output for the applicable sector. This amount is calculated for each activity defined in Table 9-1 of ARB’s Cap-and-Trade regulating summing direct emissions and indirect emissions from steam purchases for the category, netting out any direct emissions associated with sold electricity and/or steam, and then dividing this amount by total production for the category:

$$0.9 * [\text{Direct Emissions} + (\text{Steam Purchased} - \text{Steam Sold}) * \text{CCF}_{\text{Steam}} - \text{Electricity Sold} * \text{CCF}_{\text{Electricity}}] / \text{Production}$$

Where:

0.9 is the benchmark stringency chosen to reflect the emissions intensity of highly efficient, low-emitting covered entity within each industrial activity. For sectors in which there was only one covered entity or in which no covered entity was at least at the efficiency of the benchmark, the benchmark stringency was set at the average emissions efficiency (i.e., multiplied times 1.0, not 0.9).

“Direct Emissions” is the total direct emissions for the industrial sector for which the benchmark “B” is being calculated over a historical period, that results from process emissions (where applicable) and the combustion of fossil fuels onsite.

“Steam Purchased” is the total steam purchased by the sector for which the benchmark “B” is being calculated over a historical period, in MMBTU.

“Steam Sold” is the total steam sold by the sector for which the benchmark “B” is being calculated over a historical period, in MMBTU.

“CCF” is a benchmark for emissions from steam or electricity. The CCF for steam is .0663 tonne CO₂e/MMBTU_{steam}, which is consistent with a boiler utilizing natural gas and operating at 85% efficiency, and .431 tonne CO₂e/MWH for electricity, which is consistent with a natural gas emission factor.

“Electricity Sold” is the total electricity sold by the sector for which the benchmark “B” is being calculated over a historical period, in MWH.

“Production” is the total output for the industrial activity for which the benchmark is being calculated over a historical period.

“C” is the Cap Adjustment Factor applied to the allocation calculation to scale the allocation consistent with the decline in the overall GHG cap. This factor will depend on the year in which an allocation is being provided. The schedule for the Cap Adjustment Factor can be found in Table 9-2 in the ARB’s cap-and-trade regulation.

“O” is the total production from a given industrial activity subject to the product-based benchmark.

To develop an allocation that mirrors this methodology for indirect emissions, the formulation above can be left largely intact with the exception of the benchmark (“B”), which, for purposes of calculating indirect emissions can be calculated by simply dividing indirect emissions from electricity purchases by total production for the category:

$$B_{\text{purchased electricity}} = 0.9 * \Sigma(EP_{\text{covered entity}} * CCF_{\text{Electricity,utility}}) / \text{Production}$$

Where:

0.9 is the benchmark stringency chosen to reflect the emissions intensity of highly efficient, low-emitting covered entity within each sector. For sectors in which there was only one covered entity or in which no covered entity was at least at the efficiency of the benchmark, the benchmark stringency was set at the average emissions efficiency (i.e., multiplied times 1.0, not 0.9).

“ $EP_{\text{covered entity}}$ ” is the total electricity purchased by an individual covered entity within an sector for which the benchmark “B” is being calculated over a historic period in MWH.

“ $CCF_{\text{electricity,utility}}$ ” as used here is a utility-specific emissions factor for electricity delivered to the covered entity in $EP_{\text{covered entity}}$ during the historic period, calculated as the average tonnes CO_{2e}/ MWH of electricity.

“Production” is the total output for the activity for which the benchmark is being calculated over a historical period.

Substituting this formulation of the benchmark (“B” in the above equation) into the equation above results in a formula that calculates the allocation an entity subject to a product-based benchmark would receive for its indirect emissions costs from purchased electricity.

However, because the IOUs are required to consign their allocations to auction, rather than allowances, the compensation for entities for purchased electricity costs requires an additional factor to convert the allocation, denominated in tonnes of CO₂e, into dollars. Thus, we need to multiply the result from the equation above by a conversion factor, “D” representing an estimate of the cost per tonne of emissions. Given the vagaries of carbon prices in the market, we believe this conversion factor should be calculated as the sales weighted average market clearing price of allowances sold at auction of the same vintage year as the compliance year for which compensation is being sought.

With these additions, the general formula for calculating the allocation for purchased electricity costs under the product based benchmark approach becomes:

$$\text{Allocation} = A_t * B * C_t * O_{t-1} * D_t$$

Where:

“A_t” is the “assistance factor,” associated with a given sector for a given compliance year “t”. It is the percent of the emissions benchmark (described below) that will be provided in an allocation, ranging from 30% to 100%. The specific percentage is determined based on ARB determinations regarding the level of emissions intensity and trade exposure an activity is subject to and the year in which the allocation is being sought. The specific Assistance Factor that applies to a given sector can be found in Table 8-1 of the ARB’s cap-and-trade regulation.

“B” is the indirect emissions benchmark per unit output for the applicable sector. This amount is calculated for each industrial sector by summing indirect emissions from electricity purchases for a given sector and historical period,

and then dividing this amount by total production for the sector and period as described above.

“ O_{t-1} ” is the total output produced in a given compliance year “t-1” from a given covered entity receiving compensation under the product-based benchmark.

“ D_t ” is the Dollar Conversion Factor calculated based on the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided.

Under the approach we take here, the allocation amount for compliance year “t” would be calculated after the last auction for year t has occurred. For example, compensation for purchased electricity costs for the 2013 compliance year would be calculated and provided late in 2013, using 2012 production data and 2013 auction clearing prices.

These calculations should, for the most part rely on the same output data that ARB uses to calculate allowance allocations. We note that there may be some entities that would be eligible for compensation for purchased electricity costs because they belong to an industrial sector designated for industry assistance, but, because they are below the reporting and/or compliance threshold, do not submit output data to ARB. To the degree these entities wish to receive compensation for their purchased electricity, they will need to opt into the cap-and-trade program, per section 95813 of the cap-and-trade regulation.

Energy-Based Allocation

For some industrial entities, rather than adopt a product-based approach, ARB instead relies on an “Energy-based” allocation methodology reflecting estimated historical emissions from a given

covered entity. To develop these benchmarks, ARB relied on the following formula:

$$\text{Allocation}_t = (\text{S}_{\text{Consumed}} * \text{B}_{\text{Steam}} + \text{F}_{\text{Consumed}} * \text{B}_{\text{Fuel}} - \text{e}_{\text{Sold}} * \text{B}_{\text{Electricity}}) * \text{AF}_t * \text{C}_t$$

Where:

“S_{Consumed}” is the historical baseline annual arithmetic mean amount of steam consumed, measured in MMBtu, at the industrial covered entity for any industrial process, including heating or cooling applications. This value shall exclude any steam used to produce electricity. This value shall exclude steam produced from an onsite cogeneration unit;

“B_{Steam}” is the emissions efficiency benchmark per unit of steam, 0.06244 California GHG Allowances/MMBtu Steam;

“F_{Consumed}” is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at a given covered entity, measured in MMBtus. ARB’s Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (October 30, 2009). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit. This value shall exclude energy to generate the steam accounted for in the “S_{Consumed}” term;

“B_{Fuel}” is the emissions efficiency benchmark per unit of energy from fuel combustion – 0.05307 California GHG Allowances/MMBtu;

“e_{Sold}” is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWhs;

“B_{Electricity}” is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh; This is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWhs;

“AF_t” is Assistance Factor, a number representing the percent of the emissions benchmark (described below) that will be provided in an allocation, ranging from 30% to 100% in a given budget year. The specific percentage is determined based on ARB determinations regarding the level of emissions intensity and trade exposure an entity is subject to and the budget year from which the allocation is being drawn. The specific Assistance Factor that applies to a given sector and budget year can be found in Table 8-1 of the ARB’s cap-and-trade regulation.

“C_t” is the Cap Adjustment Factor applied to the allocation calculation to scale the allocation consistent with the decline in the overall GHG cap. This factor will depend on the budget year from which an allocation is being drawn. The specific cap adjustment factor values for each budget year by sector can be found in Table 9-2.

We note that under the energy-based allocation, the allocation amount an entity is eligible to receive does not change or update over time. It is established from the outset based on the variables described above, with the exception of entities that shut-down or fall below the emissions

threshold, in which case they are no longer eligible to receive allowances.¹ Additionally, to address new entrants, i.e. those entities that were not in operation prior to 2011, but are eligible for a free allocation under the energy-based approach, ARB allows the Executive Officer the ability to establish an allocation based on the covered entity's "expected activity levels".²

As with the product-based benchmarking methodology described above, this methodology does not include the indirect emissions associated with electricity purchases. To address these indirect costs under the energy-based benchmark, the following calculation should be used:

$$\text{Revenue Allocation} = e_{\text{Purchased}} * B_{\text{Electricity}} * AF_t * C_t * D_t$$

Where:

" $e_{\text{Purchased}}$ " is the historical baseline annual arithmetic mean amount of electricity purchased by a given covered entity for use onsite, measured in MWhs; This should be based on historical data either submitted to ARB, or based on utility invoices over that same, historical period.

" $B_{\text{Electricity}}$ " is the emissions efficiency benchmark per unit of electricity purchased from third parties in tonnes CO₂e/MWh. The specific emissions efficiency benchmark is specific to the third party that provided power to the entity receiving an energy-based revenue allocation over the historical period.

" AF_t " is the percent of the emissions benchmark (described below) that will be provided in an allocation, ranging from 30% to 100%. The specific percentage is determined based on

¹ ARB Cap and Trade regulation 95891.c.4.

² ARB Cap and Trade regulation 95891.c.3.

ARB determinations regarding the level of trade exposure an entity is subject to and the year in which the allocation is being sought. The specific Assistance Factor that applies to a given sector and compliance year can be found in Table 8-1 of the ARB's cap-and-trade regulation.

" C_t " is the cap adjustment factor applied to the allocation calculation to scale the allocation roughly consistent with the decline in the overall GHG cap. This factor will depend on the year for which an allocation is being sought. The specific Cap Adjustment Factor that applies to a given sector can be found in Table 9-2 of the ARB's cap and trade regulation.

" D_t " is the Dollar Conversion Factor used to convert tonnes of emissions into dollars. This value should be calculated as the sales weighted average market clearing price of the allowances sold at auction. The weighted average includes only the vintage allowances associated with the compliance year for which the emissions being compensated occur.

As with the product-based approach, the revenue allocation will be calculated and provided at the end of the given compliance year for which the compensation is being calculated. Similar to ARB's approach for direct emissions costs under the energy-based benchmark, we also need to address new entrants and facility closures. For new entrants, we need to develop a process to reasonably estimate a new entrant's electricity purchases, defined as an entity not in operation prior to 2011 that is eligible for an energy-based allocation. Should an entity, otherwise eligible to receive an energy-based allocation, cease operations, consistent with ARB's approach, it will no longer be eligible to receive an energy-based allocation to address its indirect costs.

Allocations to Refineries

As described earlier in this decision, Tesoro filed comments regarding specific concerns related to its Golden Eagle Refinery. Specifically, Tesoro argues that the Commission should address the lack of Industry Assistance that the Golden Eagle Refinery will receive from ARB for the purchase of electricity from a third-party-owned CHP unit. Tesoro points out that if the Golden Eagle refinery owned the same CHP unit, the GHG costs of its electricity production would be eligible for Industry Assistance. Tesoro argues that this mere difference in ownership status should not result in substantially different level of Industry Assistance. In order to provide assistance commensurate with a facility with on-site CHP, Tesoro suggests that the utilities be directed to set aside some of the allowance revenues they receive to cover the costs faced by refineries purchasing electricity from third-party CHP providers.

We agree that it is appropriate to address the GHG costs of electricity purchased by refineries from third-party CHP through the use of the allowance revenues the utilities will receive in a manner consistent with the intent of Tesoro's request. The ARB approach to allowance allocation to the refinery sector during the first compliance period employs a two-tiered approach. First, the sector is allocated allowances on a simple product-based, "simple barrel" benchmark identical to that utilized for other product-based benchmarks, but where the allocation is based on sector production from two year's prior, the refinery assistance factor, the cap adjustment factor, and a benchmark of 0.0462 allowances per barrel of primary refinery product. By using the simple barrel metric to evaluate GHG intensity for the sector as a whole, the sector allocation is transparent

and based on information that can generally be made publicly available. The total amount of allowances allocated to the sector can increase or decrease automatically in response to future production levels of refinery products consistent with the product-based allocation approach for producers in other sectors. Likewise, the performance goal (benchmark stringency) for the sector is directly comparable to what is required for other industrial sectors.

Allocation to individual refineries is determined depending on the complexity of the refinery. Simple and complex refineries are differentiated in the allocation to individual refineries because complex refineries conduct a variety of emissions-intensive processes that are disadvantaged under the simple barrel metric. For so-called “simple” refineries (i.e., those without a Solomon Energy Efficiency Index®, described below), covered entity-level allocations are provided using the same formula if emissions are at or below historical levels, and at a baseline level of emissions (allocation = assistance factor x baseline level of emissions x cap adjustment factor) if emissions are in excess of historical levels. The remainder of refinery-sector allowances (i.e., those remaining after those allowances allocated to simple refineries are subtracted from the sector allocation), are divided amongst those refineries with a Solomon Energy Efficiency Index® (EII) value based on the historical emissions of each refinery. EII, an adjustment factor to reduce competitiveness impacts of allowance allocation between in-state refineries, and future emissions for each refinery.

The Solomon EII is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates, which has been

developing energy efficiency benchmarks relied upon by the industry for the past 30 years. They maintain an extensive database of more than 500 refineries' energy consumption and process data, covering over 85 percent of global refinery capacity, which is used to develop the EII values. The Solomon EII is the industry standard for comparing energy efficiency across refineries globally. California refineries that have a Solomon EII value represent over 90 percent of the refining capacity in the state.

Although EII value is a complexity-adjusted measurement of energy efficiency and not greenhouse gas efficiency, we believe it provides an appropriate performance metric for complex facilities. The metric is well understood by all complex facilities and has been recognized under the U.S. Environmental Protection Agency's Energy-Star Program. Under ARB's approach, and the parallel approach proposed here for emissions from electricity purchased by refineries, the covered entity with the best (most efficient) EII will receive the greatest portion of their historical emissions baseline, and less efficient facilities will receive small portions of their individual historical emissions baseline. A true up using actual emissions will occur at the end of the first compliance period to ensure there is no excessive under or over allocation.

Though ARB's approach to providing compensation to refineries is complex, we believe the benefits of pursuing a comparable approach to address indirect emissions costs embedded in electricity purchases outweighs the administrative costs of doing so, particularly in light of the fact that it applies the appropriate incentive of encouraging the efficient use of electricity. In order to provide allowance value on this basis, we first need to calculate the allowances needed for the refining sector as a

whole to cover their indirect emissions. This is accomplished using an approach comparable to that outlined for the product-based allocation methodology for purchased electricity:

$$SA_{EP} = A_t * B * C * O$$

Where:

“SA_{EP}” is the annual allocation to the refining sector for emissions from purchased electricity for budget year t.

“A_t” is the assistance factor for budget year t assigned to petroleum refining as specified in Table 8-1.

“B” is the benchmark for primary products produced by the refining sector, and is determined by the following equation:

$$B_{\text{refineries}} = 0.9 * \Sigma(\text{EP}_{\text{covered entity}} * \text{CCF}_{\text{electricity,utility}}) / \text{Production}$$

Where:

0.9 is the benchmark stringency chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities within the sector.

“EP_{covered entity}” is the total electricity purchased by an individual covered entity within the refinery sector for which the benchmark “B_{refineries}” is being calculated over a historic period, in MWH.

“CCF_{electricity,utility}” as used here is a utility-specific emissions factor for electricity delivered to the covered entity during the historic period, calculated as the average tonnes CO_{2e}/MWH of electricity.

“Production” is the total output for the sector for which the benchmark is being calculated over a historical period.

“ C_t ” is the cap adjustment factor for budget year t assigned to petroleum refining to account for cap decline as specified in Table 9-2.

“ O_{t-1} ” is the output of primary refinery products, in barrels, from the refining sector in year $t-1$.

Refineries without an EII value would be allocated to based on the following approach:

If: $A_t * B * C_t * O_{t-1} \leq A_t * BE * C_t$

Then: $\text{Revenue Allocation}_t = A_t * B * C_t * O_{t-1} * D_t$

If: $A_t * B * C_t * O_{t-1} > A_t * BE * C_t$

Then: $\text{Revenue Allocation}_t = A_t * BE * C_t * D_t$

Where:

“ $A_{X,t}$ ” is the allocation to refinery “X” without an EII value for year t .

“B” is the benchmark for the refinery sector for emissions from purchased electricity, as calculated on the previous page.

“ C_t ” is the adjustment factor for budget year t assigned to petroleum refining to account for cap decline as specified in Table 9-2.

“ $O_{X,t-1}$ ” is the output of primary refinery products, in barrels, from refinery “X” in year $t-1$.

“ BE_X ” is the average annual greenhouse gas emissions for purchased electricity for refinery “X” over a historical period.

“D_t” is the Dollar Conversion Factor used to convert tonnes of emissions into dollars. This value should be calculated as the sales weighted average market clearing price of the allowances sold at auction. The weighted average includes only the vintage allowances associated with the compliance year for which the emissions being compensated occur.

Refineries with an EII value would be allocated to based on the following approach:

$$\text{Revenue Allocation}_t = BE_Y * DF_{Y,t} * F_t * D_t$$

Where:

“A_{Y,t}” is the initial allocation to refinery “Y” that has an EII value for year “t”.

“BE_Y” is the average annual greenhouse gas emissions for purchased electricity for refinery “Y” over a historical period.

“DF_{Y,t}” is a distribution factor calculated as:

$$DF_{Y,t} = ((Avg / EII_Y) + Adj_t) / (1 + Adj_t)$$

“Avg” is the weighted average EII for all facilities with EII values calculated as:

$$Avg = \frac{\sum BE_Y}{\sum (BE_Y / EII_Y)}$$

“EII_Y” is the Solomon Energy Intensity Index (EII) for covered entity Y for 2008, 2009 or 2010 as determined to be representative by the ARB’s Executive Officer. For the purposes of this calculation, EII values shall be rounded to one digit after the decimal.

"Adj" is an adjustment factor designed to provide the covered entity with the best EII the most allowances relative to its baseline level:

$$Adj_t = ((Avg/EII_{Best}) * F_t - 1) / (1 - F_t)$$

"EII_{Best}" is the EII of most efficient covered entity (lowest EII in sector);

"F_t" is a fraction calculated as:

$$F_t = \frac{SA_{EP} - \sum A_{X,t}}{\sum BE_Y}$$

"D_t" is the Dollar Conversion Factor used to convert tonnes of emissions into dollars. This value should be calculated as the sales weighted average market clearing price of the allowances sold at auction. The weighted average includes only the vintage allowances associated with the compliance year for which the emissions being compensated occur.

If actual 2013 and 2014 emissions from purchased electricity are less than the revenue provided, the entity will need to reimburse the utility providing revenue according to the following true-up debit equation:

$$\begin{aligned} \text{If: } & (AE_{Y,2013} + AE_{Y,2014}) < (A_{Y,2013} + A_{Y,2014}) \\ \text{Then: } & A_{Y,Debit} = 0.8 * [(AE_{Y,2013} + AE_{Y,2014}) - (A_{Y,2013} + A_{Y,2014})] \end{aligned}$$

Where:

"AE_{Y,t}" = Actual GHG emissions for purchased electricity in year t.

"A_{Y,Debit}" = A debit (shown as a negative value in the equation above) to be surrendered to the providing utility by refinery "Y."

If actual 2013 and 2014 emissions from purchased electricity are greater than the revenue provided, a true-up allocation will be conducted using 2015 vintage allowances and the following true-up credit equation:

$$\text{If: } (2 * BE_Y) < (AE_{Y,2013} + AE_{Y,2014})$$

Then:

$$A_{Y,Credit} = (AE_{Y,2013} * DF_{Y,2013} * F_{2013} * A_{2013} + AE_{Y,2014} * DF_{Y,2014} * F_{2014} * A_{2014}) - (A_{Y,2013} + A_{Y,2014})$$

Where:

"A_{Y,Credit}" = An true-up revenue provided to refinery "Y."

This metric is preferable to the approach for the first compliance period because it is based on greenhouse gas intensity and adjusts to recognize refinery complexity. The method also is not dependent on a proprietary index and, therefore, is somewhat more transparent.

During the second compliance period of the cap-and-trade program, ARB will utilize a uniform complexity-adjusted approach. This method will employ the Carbon Dioxide-Weighted Tonne (CWT) metric initially developed for the European Union's Emission Trading Scheme. Extensive work has been conducted using a robust dataset of European refineries to create the CWT approach. Under the approach, refineries will report throughput or product values for a variety of processes to ARB, and ARB will convert these throughput values into CWT equivalent. Each covered

entity will receive allowances based on the product output-based equation and the CWT benchmark value of 0.0295 allowances per CWT.

ARB staff plans to conduct additional technical work on the CWT approach in 2012, and will recommend any appropriate changes to the Board resulting from this analysis in a future regulatory package. Given this ongoing work, it may be necessary to revisit the reimbursement to refineries after ARB determines if any changes to the CWT approach may be necessary.

(END OF APPENDIX A)

APPENDIX B:
Proposed Methodology for Calculating Allowance Value to
Compensate Small Businesses for Purchased Electricity Costs Resulting
from the Cap-and-Trade Program

$$\text{Allocation} = A * G$$

Where:

“A” is the Industry Assistance Factor for the low leakage risk classification (100%, 50%, and 30% for the first, second and third compliance periods, respectively). This assistance factor can be found in Table 8-1 of ARB’s Cap-and-Trade regulation.

“G” is the GHG Cap-and-Trade-related cost, in dollars per kilowatt-hour, that is included in a small business ratepayer’s particular electricity tariff. This is the Cap-and-Trade-related cost that each investor-owned utility will incur, which the ERRA proceeding authorizes the investor-owned utilities to recover from the generation component of rates, and that is apportioned to each electricity tariff via allocation factors. This cost will therefore vary depending on the tariff of each small business.

(END OF APPENDIX B)